A CBO STUDY

Promoting Efficiency in the Electric Utility Sector

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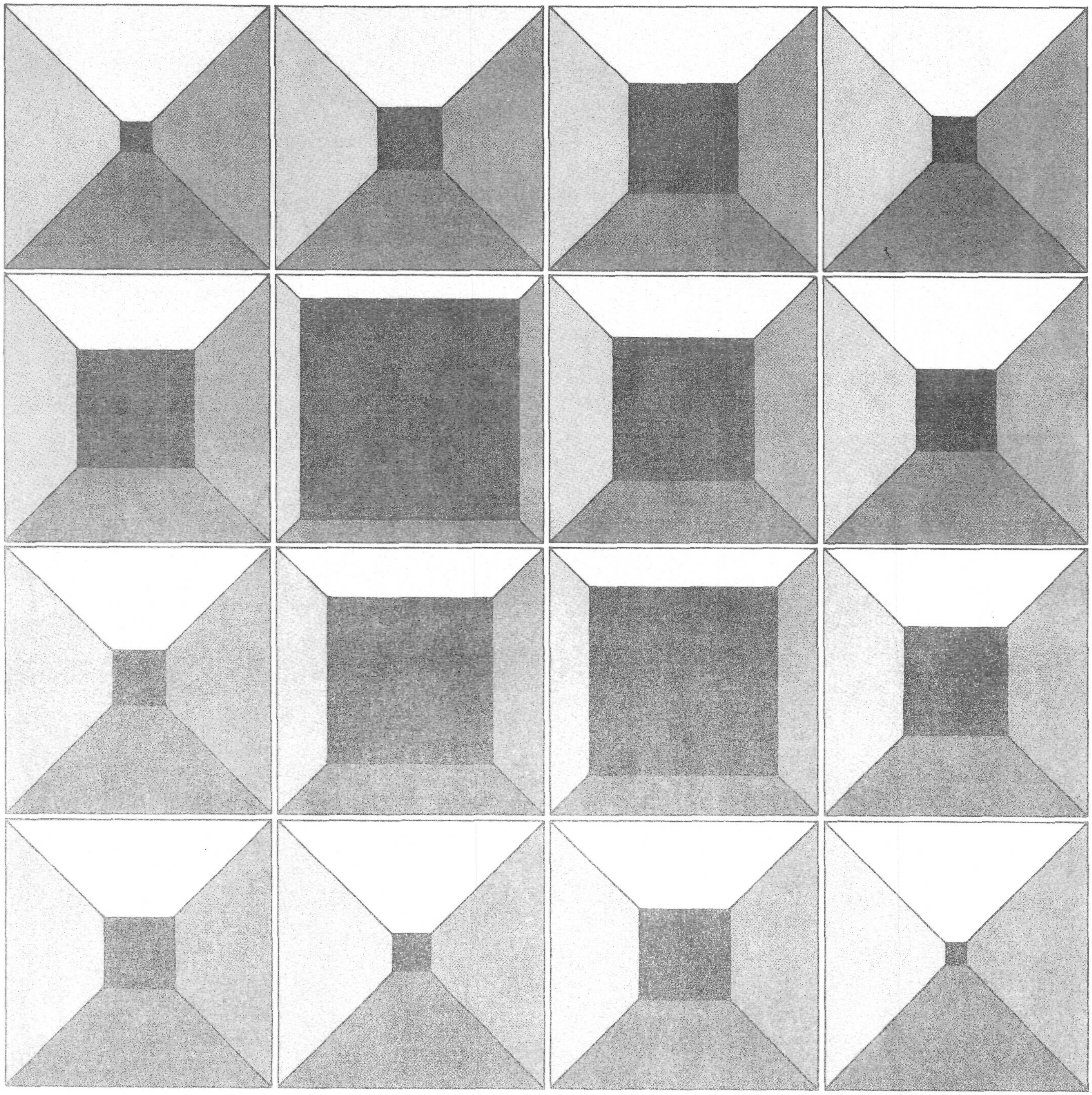
Congress of the United States
Congressional Budget Office



PROMOTING EFFICIENCY IN THE ELECTRIC UTILITY SECTOR

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PREFACE

The electric utility industry consumes a large amount of oil and gas in the production of electricity--the equivalent of 2.6 million barrels per day. In many cases electricity could be produced more economically if greater use was made of alternative energy sources, notably of coal. A shift to alternative fuels would mean retiring oil- and gas-fired generating equipment or converting it to coal, as well as speeding up the construction of new generating capacity. The utility industry may have been handicapped in making the shift by regulatory constraints. To be sure, other factors such as the slow and erratic growth in demand for electricity have contributed to this situation. Yet to the extent that the regulatory process prevents the utility industry from responding to economic signals regarding fuel choice, a case may be made for a change in public policy. The issue is whether regulatory changes would help to increase the flexibility of utilities in altering their generating capacity, resulting in more adequate future supplies and lower long-term electricity prices.

At the request of the minority staff of the Senate Committee on Energy and Natural Resources, the Congressional Budget Office has prepared this analysis of the regulatory treatment of electric utilities and its relation to the efficiency of the electric utility industry in general and utility fuel choice in particular. In keeping with CBO's mandate to provide objective analysis, the report contains no recommendations.

The report was written by Gary J. Mahrenholz of CBO's Natural Resources and Commerce Division, under the supervision of David L. Bodde and Everett M. Ehrlich. John Jensen and Paul Higgins provided research assistance. Francis Pierce edited the manuscript, which was typed for publication by Deborah L. Dove.

Alice M. Rivlin
Director

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SUMMARY

The economic performance of the electric utility industry is strongly influenced by its financial prospects and by the way it is regulated. The general financial decline of electric utilities during the 1970s, coupled with certain regulatory practices of state public utility commissions, may inhibit utilities in adjusting to the demands of the 1980s. This paper examines the sources of inefficiency in the electric utility sector--particularly as they affect the choice of fuels--and discusses some policy options that might promote greater efficiency in the generation of electricity.

REGULATION AND UTILITY FUEL CHOICE

Present-day regulation of electric utilities is premised on a 1944 Supreme Court decision in the case of Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591. The court held that the purpose of regulation is to provide the utility with a rate of return sufficient to attract capital and to reward investors commensurate with their risks. This ruling gave the state Public Utility Commissions (PUCs), which regulate intrastate electricity sales, considerable discretionary authority. During the 1960s, utilities prospered in their regulatory environment, largely because of continual cost decreases associated with technological progress and larger-scale operations. This situation was reversed in the 1970s. Fuel prices rose in response to the 1973-1974 and 1979-1980 oil price shocks. New costs for environmental protection were imposed on utilities by the Clean Air Act. Construction costs rose rapidly. Moreover, as prices rose and profits fell, electric utility regulation became lengthier and more contentious; the slowness of the regulatory process combined with inflation to erode the rate of return allowed utilities. Thus in 1980, while the cost of capital had risen to about 16 percent, utilities were being allowed an average 14 percent rate of return and realizing a return of only 12 percent.

The deteriorating financial condition of electric utilities, coupled with the way they are regulated, has impaired the industry's ability to make new investments in generating plants. To be sure, many of the recent cancellations or deferrals of new generating capacity have been related to the fact that growth in electricity demand has been slower and more erratic than expected. Yet there is also evidence that much new capacity is being deferred that would be economic.

In 1981, for example, over 2.6 million barrels per day of oil and gas (equivalent) were burned under utility boilers. About two-thirds of this amount is uneconomic at current oil prices. Where oil and gas are used for baseload generation, the long-run cost of new generating capacity using alternative fuels, most often coal, is frequently lower than the cost of continued baseload generation with oil and gas. This is because the capital and fuel cost of a new power plant is less than the fuel cost of oil or gas for the existing power plants. Thus while the efficient combination of capital and fuel varies sharply with the characteristics of the individual utility, much of the electric sector may be now far from its most efficient configuration.

Several interrelated factors inhibit reductions in utility oil and gas consumption. First, it is administratively simple for most utilities to pass fuel costs through to customers. In the 1970s, most state regulators provided their utilities with "fuel adjustment clauses" in response to the rapid increases in fuel prices. These provisions allowed a utility to recover its fuel costs rapidly enough to prevent a cash flow crisis. But they also reduced the utility's incentive to retire or convert oil- and gas-fired units. Adding new or replacement capacity requires the utility to incur capital costs, and lengthy and uncertain regulatory proceedings must take place before their recovery.

Second, there is an asymmetry of risk between the principal stakeholders in utility ratemaking: ratepayers and stockholders. Utilities that undertake the building of new plants to replace oil and gas capacity must generally pass the resulting savings on to ratepayers if all goes well. But if difficulties arise with the new plant, the costs are borne first by the stockholders and only later by the ratepayers. Thus, the rewards of new investment tend to accrue to ratepayers rather than to stockholders, while the risks are shared by both. This imbalance tends to bias investment decisions away from projects involving significant capital expenditures or innovative technologies. In contrast, ratepayers absorb most of the cost of increased oil prices through the use of fuel adjustment clauses.

The replacement of oil- and gas-fired capacity is also inhibited by the regulatory treatment of construction costs. If utilities are to recoup their construction costs as they are incurred, they must raise electricity rates. While the construction may lead to lower costs in the long term, state regulators are often unwilling to allow rates to rise in the short term. Thus, rather than allow recoupment of costs as they are incurred, PUCs generally provide utilities with an "allowance for funds used during construction" (AFUDC). Under this procedure, construction costs are included in a special account that earns interest but is not allowed into the utility's rate base until the project is complete. Even though AFUDC accounts are not realized as cash by the utility, they are treated as income by regulators. The effect of this procedure can be seen by subtracting AFUDC accounts from stated earnings. When this is done, the rate of return for utilities in 1980 falls from about 12.0 to 6.4 percent. In contrast, the rate of return earned in all manufacturing in that year was 16.4 percent.

These regulatory practices may have the effect of biasing electric utilities against capital-intensive projects. This would tend to lock the electric generating sector into capital equipment that is economically obsolete, with two consequences: the uneconomic use of fuels in generating, and an unnecessary limitation on future supplies of energy.

POLICY OPTIONS

The proper objective of policy is neither the promotion nor the discouragement of electric energy use. Rather, it should be the provision of energy-based services at the lowest real cost to the economy when all external effects are considered. The nation's ability to reach this goal depends in large part on the ability of the utility sector to make timely adjustments to its capital equipment and to use the least-cost combination of fuels. This does not mean displacing oil and gas in all their applications in the electric sector, but rather allowing utilities to displace oil and gas in favor of alternative fuels when warranted by economic considerations.

While allowing economic considerations full sway may be an appropriate goal of public policy, the federal role in pursuing this goal is limited. The states have the reserved legal right to regulate the conduct of utilities within their boundaries. Any policy thrust that seeks to influence the regulatory process, therefore, requires that the federal government preempt this right. This may make policy options aimed at improving the regulatory process difficult to enact; it should be noted that comparable legislation, such as the Public Utility Regulatory Policy Act, has been under challenge in the courts.

Despite this limitation, a number of policy options are available that may facilitate capacity adjustment by electric utilities. These options can be divided into two groups--those that would affect the conduct of the regulatory process and those that would not. The latter include:

- o Reliance on general economic recovery. Improved economic conditions may lower the rates of inflation and interest, making new capital projects less expensive. In that case, no specific policy may be necessary beyond those now in place.

- Subsidization. Privately-owned utilities could be subsidized in making capacity adjustments, particularly if they involve substituting new baseload capacity for oil and gas. This could be done either through cash subsidies or by further liberalizing the investment tax credit and accelerated depreciation.

Another set of options would amend regulatory practices. These include:

- Imposing federal rulemaking on state regulatory commissions. The federal government could determine rules regarding specific regulatory practices (such as the use of AFUDC or fuel adjustment clauses, or the determination of allowed rates of return) that states would be compelled, or induced, to adhere to.

- Regional capacity planning. Capacity planning could be done on a regional rather than local basis to achieve greater efficiency and lower requirements for reserve margins.

- Introducing more competition through deregulating the generation stage of electricity production. The franchised monopoly position of electricity generation could be amended to allow free competition among bulk suppliers of electricity. Transmission and distribution would remain subject to regulation.

It should be noted that these regulatory options are not mutually exclusive. Some, in fact, are complementary, and can be considered in conjunction.

The Policies Compared

Each option would have different implications from the standpoints of efficiency and fairness. The efficiency of a policy would depend upon its cost-effectiveness and the rapidity with which it achieved economic capacity adjustments. A policy is fair to the extent that those who benefit from changes in generating capacity would pay for them.

Efficiency. The three regulatory reform options may offer significant advantages over the others. A subsidy might confer windfalls on utilities that would have been able to adjust with less subsidization, while neglecting some utilities that might require more. A subsidy also rewards managerial inefficiency. Moreover, subsidies only treat the symptoms and not the causes of financial weakness. In that case they might not improve the financial rating of utilities and reduce their capital charges. Furthermore, a subsidy shields ratepayers from the true cost of energy at a time when economic efficiency requires the appropriate use of price signals. If half the oil- and gas-fired capacity that cannot be converted to coal were retired ahead of schedule and 10 percent of their replacement capital costs were defrayed through subsidy, the cost to the federal government would exceed $6 billion.

The other nonregulatory option--that of reliance on general economic recovery--would not bring about any improvement in regulatory policies. If the economy recovers, and interest and inflation rates drop, state PUCs may simply pass the bulk of these benefits directly to ratepayers without increasing the utilities' rate of return. This would do nothing to relieve the utilities' difficulty in raising new capital.

Changes in regulatory practices could do much to improve the financial position of electric utilities. In particular, federal standards that would grant utilities adequate rate relief might enable them to raise capital at less cost and pursue the necessary changes in capacity. Of special interest are provisions linking utility earnings and performance. If utility investments in new capacity or changes in their fuel mix resulted in lower generating costs, then utilities could be allowed some share of the avoided costs. This procedure would give utilities strong incentives to adjust their capital stock in the face of changing economic conditions.

Regional capacity planning would complement the other options. Utility systems have become increasingly integrated since 1965, but capacity planning is still done predominantly from a state perspective. Requiring capacity planning on a regional basis could lower the amount of capacity that state utilities must hold in reserve, without lowering reliability levels; it could also contribute to conservation and load management. Least-cost investments could be encouraged, such as substituting linkages to out-of-state power plants for new intrastate construction. Regional planning could also help to overcome two major obstacles to new power plant construction--the risks associated with demand uncertainty, and delays in siting and licensing.

Competition could be increased by deregulating the generation stage of electricity production. Distribution would still be regulated by state PUCs, while the transmission of electric power might be controlled by the Federal Energy Regulatory Commission. The efficiency effects of such deregulation are unclear. It might mean less service reliability, since independent generating companies would not be obligated (as they are now) to meet all levels of demand. Thus, they might forecast load growth conservatively and be unwilling to provide more expensive peak power. In addition, if state PUCs simply passed generation costs on through the distribution stage, the incentive for price competition among generating companies could be blunted. On the other hand, deregulation might encourage greater efficiency since competition would give preference to least-cost generating options.

Fairness

As used here, fairness means that those who receive the benefits pay for them. If the Congress adopted no specific policy, then no additional direct costs would be imposed on anyone: ratepayers, utility stockholders, or taxpayers. Yet, this might be inequitable if it meant continuing the current state PUC practices. The failure of PUCs to make economic investment decisions imposes a burden of inefficiency upon those served by the utility system--in effect, a regressive tax.

Subsidies also pose fairness problems. If capacity adjustments are in the interest of ratepayers, it can be argued that they--rather than taxpayers--should bear the cost of making them.

The regulatory reform options appear more equitable in that they assign the costs of capital adjustment to the primary beneficiaries--ratepayers. The principal difficulty derives from the distribution of costs and benefits over time. Current ratepayers would finance capital stock adjustments that would benefit future ratepayers. This difficulty is offset by several considerations. First, current and future ratepayers are frequently the same people. Second, subsidies across time are hardly a new phenomenon. Schools, soil conservation, and research in childhood diseases are but a few of many examples of intergenerational subsidization. Finally, deferring the recovery of capital charges into the future--rather than assigning them to current ratepayers--makes the utility business more risky for investors, raising the cost of capital and causing utilities to postpone construction that would otherwise be economic. To the extent that current policy does this, it may impose special costs on future ratepayers. It is not clear that reversing the policy would be inequitable.

In sum, changes in certain regulatory practices might expedite needed capacity adjustment. This option would be strengthened if combined with regional regulation and the introduction of greater competition within the industry's present structure. Greater competition might pose certain risks, but it could give a powerful boost to least-cost generation of electricity.

Some Concluding Observations

The problem posed by the nation's electric utilities is that their financial condition and regulatory treatment blunt their incentive to reach the most efficient long-term combination of capital and fuels available to them. The result is not likely to be widespread electricity shortages. Rather, in the face of impending shortages, utilities would call up otherwise uneconomic peaking units--predominantly fired by oil and gas. Thus, the economic losses associated with an inefficient electric utility sector are the additional--and unnecessary--costs of this type of generating capacity. Electricity would simply cost more than it needs to.

The financial condition and regulatory treatment of electric utilities are intertwined. Thus, any policy proposal that seeks to address inefficiency in the electricity generating industry must address the regulatory process. But federal intervention in the regulatory process would necessarily reduce the discretion of states to regulate electricity prices as they see fit. Whether existing state prerogatives could be abridged without lengthy legal challenges is unclear. In the final analysis, the efficiency and equity advantages of regulatory reform options must be weighed against their impact upon the traditional rights of states to conduct electricity regulation.

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CHAPTER I. INTRODUCTION

The decade of the 1970s witnessed a series of profound changes in the circumstances under which electric utilities operate. While in earlier decades the industry had experienced steady growth in demand together with declining costs, the 1970s were a time of disturbance. An upheaval occurred in energy prices, while internally the industry had to face rising fuel and capital costs together with new costs imposed by environmental policies. Future demand for electricity became more difficult to forecast. These problems were exacerbated by a regulatory process that was not designed to deal with them. As a consequence, the efficiency of the electric utility sector may be eroding.

The future of electric utilities may require significant adaptation to these new conditions through changes in generating capacity. At present, the utilities find it difficult to raise the funds needed for investment in least-cost generation. Inability to raise capital occurs in many industries, but electric utilities are unique in four respects. First, they deploy more capital than any other industry--30 percent of total U.S. manufacturing investment annually. Second, because they have local monopoly franchises, inefficiencies in electricity production are ultimately imposed on consumers in the form of higher costs. Third, the utility capital problem is bound up with the present regulatory system, and a solution to it may require a change in public policy on the federal level. Fourth, utilities are major consumers of oil and gas and hence of special interest to national energy policy.

Inadequacies in the present regulatory treatment of utilities may be costly to the economy in several ways. First, utilities may use too much oil and gas because they are unable to make the capital commitments necessary to replace oil- and gas-fired capacity with coal-fired or nuclear capacity--raising the long-term costs of electricity and keeping oil imports unnecessarily high. Second, utilities may have to pay high interest rates for capital because their regulatory treatment renders them unattractive to investors. Third, the supply of electricity may fail to keep pace with the demands of the economy.

This report reviews a number of policy options intended to promote improved economic performance in the electric utility industry. Chapter II begins with a discussion of the regulatory environment of public utilities and the obstacles this environment poses to greater efficiency. In particular, the chapter reviews the financial condition of the electric utility industry and its relationship to the regulatory process. Chapter III deals with the most widely noted manifestation of poor economic performance in the electric utility sector--the continued uneconomic consumption of oil and gas. The economics of converting or retiring such units is discussed. Chapter IV analyzes the possible effects of alternative policies designed to assist utilities in promoting economic efficiency through capacity adjustment.

CHAPTER II. RATE BASE REGULATION AND THE ECONOMIC PERFORMANCE OF ELECTRIC UTILITIES

Most privately-owned electric utilities are granted monopoly franchises for their service areas, and their prices are regulated at both the federal and state levels. Interstate wholesale electricity transactions, roughly 5 percent of all utility sales, are regulated by the Federal Energy Regulatory Commission (FERC). But the bulk of electricity transactions are intrastate retail sales of electricity, and these are regulated by state public utility commissions (PUCs).

The primary concern of PUCs is to assure that ratepayers are given reliable service at "just and reasonable" rates, while allowing adequate revenues for the utilities providing such service. PUCs do this by setting electricity prices through a process termed "rate base regulation." This chapter describes the rate base regulatory process and its performance, particularly during the 1970s. It also discusses the financial condition of the electric utility industry and its dependence on the regulatory process.

ELECTRIC UTILITY REGULATION

Electricity sales have been regulated since the beginning of this century. Current regulatory procedures, however, owe much to the Supreme Court's decision in the Hope Natural Gas case of 1944.

The Hope Decision

In the early 1900s, the major debate in electricity rate cases centered on determination of a "fair value" for a utility's assets, or "rate base." Utilities argued that their assets should be valued at original cost during deflationary periods and at replacement cost during inflationary periods. Over time, original cost became the predominant method of rate base valuation, and the debate shifted to the determination of a "fair" rate of return. One impetus for this shift was the Hope decision 1944. Essentially pragmatic, it stated:

> Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might

produce a meager return on the so-called "fair value" rate base.[1]

Three regulatory principles have been distilled from this decision:

- o Investors in utilities should earn a return comparable to that earned in other businesses with comparable risks and uncertainties;

- o The allowed return should ensure the financial integrity of investments in a utility; and

- o The allowed return should be sufficient to attract the necessary capital for a utility.

The Hope decision became the precedent that state PUCs follow in assessing adequate revenue requirements for utilities in their jurisdictions. But it established no precise formula for doing so. It did not matter to the court whether a utility earned a low return on a high capital base, or a high return on a small base, as long as these principles were upheld. As a result, PUCs now have considerable discretion with regard to the actual procedures used to determine rates.

Determination of Revenue Requirements

The determination of adequate utility revenues occurs within the context of a quasijudicial rate case hearing at which the utility's prices, or rates, are set. Following the precedent of the Hope decision, utility revenues would be considered adequate when the prices utilities charge for their electricity sales are equal to the costs of providing electricity ("cost of service"), plus some subjective "fair" rate of return on the value of the utility's assets (the rate base). Thus, there are three major judgments a PUC must make in a rate case: the cost of service, the value and content of the rate base, and the rate of return on this rate base.

There is little theoretical disagreement as to what the cost of service should comprise. Allowable expenses include fuel costs, operation and maintenance costs, depreciation of the capital stock, administrative expenses, and taxes. An estimate of total expenses for the coming year is typically derived by utilizing an historical "test year." A test year is usually

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1. Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

the most recent 12-month period for which complete financial data are available. Yet "test year" expenses often may not be representative and will require adjustments, as when there is a sudden increase in the price of fuel. During inflationary times, of course, an historical test year will underestimate revenue requirements.

Beyond the choice of a test year, the controversial issues in a rate hearing generally concern the rate base and the allowed rate of return. The rate base is the electric utility's gross capital investment less accumulated depreciation--in essence, the value of that property which is "used and useful" in producing and delivering electricity. As such it includes the values of all physical assets of the electric utility--land, buildings, generation stations, and transmission facilities. These can be valued using one of three methods: original cost, replacement cost, or "fair value," which constitutes a compromise between the first two. All but five state PUCs utilize the original-cost method of rate base valuation calculated at the year's end or as an average over the year. The others use a "fair value" method.

An electric utility's allowed rate of return is usually related to the cost of capital: the weighted average of the return to be paid on long-term debt (bonds) and preferred and common stock (equity). For debt and preferred stock, the annual interest or dividend requirement is fixed, and its determination is straightforward. The rate of return on common equity is not fixed and hence is more difficult to determine. Historically, determination of the rate of return on common equity and the rate base have occupied the largest part of rate cases, since the rate allowed on common equity will affect the utility's ability to raise capital competitively.

Issues in Rate Base Regulation

The principal issues that PUCs face in determining utility revenue requirements include:

- Whether or not to allow construction work in progress to be included in the rate base;
- How to derive a "fair" rate of return on the rate base;
- Which of various accounting practices to use; and
- The use of fuel adjustment clauses.

Construction Work in Progress (CWIP). Traditionally, utilities have not been allowed to earn a return on CWIP. This means that capital expenditures on plant and equipment and on transmission and distribution facilities that are still under construction, but not yet "used and useful," are not included in the rate base. Instead, these funds are segregated in a special account--the Allowance for Funds Used During Construction account (AFUDC). The AFUDC return is calculated by multiplying the value of the utility's construction work in progress by the allowed rate of return on capital. This amount appears on the books as income for accounting purposes, but will not be realized as income by the utility until the facility is placed in service. At that time the (capitalized) AFUDC income, along with total construction costs, will be placed in the rate base and earn the rate of return applied to the rest of the utility's capital. This amount will be depreciated over the life of the new facility, and an annual return will be allowed on the undepreciated portion. Until then, the utility must maintain its cash flow in other ways.

The most common argument against the inclusion of CWIP in the rate base is that it would require current ratepayers to subsidize future ratepayers. Yet, there is emerging evidence that the opposite may occur. Since AFUDC is only accounting income and not cash, its use reduces short-run cash flow. Therefore, as AFUDC increases as a percent of a utility's total revenues, the "quality" of utility earnings is diminished, and the likelihood that the utility will be unable to meet its bills increases. The investment community then perceives lending to the utility as riskier, and interest costs rise. Thus, it is not always in the best interest of current ratepayers to favor the use of AFUDC rather than CWIP, if higher interest costs are reflected in current rates. Perhaps more important, incentives to make economic capital expenditures may be reduced if AFUDC is employed.

<u>"Fair" Rates of Return</u>. The "fair" rate of return is derived from a utility's cost of capital. The cost of capital is weighted in proportion to the amount of debt, preferred stock, and common stock comprising the utility's capital structure. Interest payments on long-term debt are fixed, as are the dividends on preferred stock. Thus, the most controversial part of the rate case is the determination of a fair return on common stock.

The cost of common equity is higher than either bonds or preferred stock. This is because bondholders and preferred stockholders have rights to payment prior to those for common shareholders, so that common stock is riskier than bonds or preferred stock. In determining a rate of return on common equity, this risk must be assessed by examining the capital structure of the utility. The larger the percentage of preferred stock and debt, the more risky is the common stock, justifying a higher rate of return.

Another type of risk to be considered in rate-of-return determination derives from one of the principles of the Hope decision: that a utility should earn a return comparable to other companies facing circumstances of similar risk. Determination of "similar risk" may not be practical in rate case hearings, since there will be disagreement as to the appropriate set of firms with similar risks. In addition, mathematical methods are sometimes used to help regulators determine a "fair" rate of return on common equity. Chief among these are the discounted cash flow technique--the most frequently used--and the capital asset pricing model, which is new but growing in popularity. But inevitably a large subjective element will remain.

Regulatory Accounting Techniques. Accounting practices pose two important regulatory choices affecting the electric utility sector: the choice between "flow-through" and normalized treatment of federal tax subsidies, and the choice of test period for cost estimation. The first choice concerns the regulatory treatment of federal tax benefits. Flow-through treatment passes the utility's tax benefits from accelerated depreciation and the investment tax credit through to ratepayers in the year that these benefits occur. Under flow-through accounting, tax benefits directly subsidize electricity use rather than the cash-flow position of the utility. By contrast, normalized treatment passes these benefits on more slowly than they are received, by amortizing the tax subsidy over the life of the capital asset that produced it. This increases the utility's effective cash flow and provides a smaller immediate benefit to ratepayers. Most states now use the normalized method for investment tax credits and accelerated depreciation. Under the Economic Recovery Tax Act of 1981, normalization of the investment tax credit and accelerated depreciation is mandatory for public utility property placed in service after 1980.

The choice of an accounting test period for estimating costs is very important during inflationary times because of the inherent regulatory lag encountered in the processing of rate cases. The average decision time for rate cases over the past five years has been eight and one-half months, and many cost estimates are outdated by the time rates go into effect. To the extent that this occurs, the utility finds it difficult to realize the revenue requirements settled in the rate case. This is especially true for cost estimates based on historical data, usually some past 12-month period. Currently, no PUCs use strictly historical test periods. Rather, most utilize an adjusted historical test period in which cost data are adjusted for known inflation. A number of PUCs utilize a partially projected test period, typically a combination of six months of adjusted historical data and six months of projected data. A few PUCs use a test period totally comprised of projected data.

Fuel Adjustment Clauses. Because of the time lag that characterizes ratemaking proceedings, PUCs have had to find a way to deal with the

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unanticipated increases in fuel prices of recent years. Fuel adjustment clauses (FACs) have been the regulatory response to this problem. All but seven PUCs use some sort of fuel adjustment clause. These clauses allow the recoupment of increases in fuel costs between rate hearings by increasing rates outside the context of a full rate case. There are a variety of such clauses, allowing all or part of the fuel cost increase to be recouped immediately or with a specific time lag. Again, each PUC uses its own discretion in designing a fuel adjustment clause it feels is appropriate for its jurisdiction.

While the use of FACs may be justifiable as a short-term measure to protect utility earnings in times of rapid and unpredictable escalation in fuel prices (such as the oil price shocks of 1973 and 1979), it can create a number of perverse incentives. Most importantly, it may deter a utility from undertaking investments to change its fuel mix. Given the long lead times required for new capacity additions, this can entail significant long-term inefficiencies.

FACs can also create short-term inefficiencies. A utility with such a clause may not bargain effectively for the lowest-priced fuel available. Similarly, operation and maintenance expenditures may not be kept at appropriate levels, increasing downtime for repairs. This diminution in reliability may force the utility to use less efficient units of its own, or to purchase replacement power from another utility (often oil- or gas-fired). A number of studies have attempted to quantify the inefficiencies such perverse incentives produce. One recent endeavor estimated the combined losses from fuel-switching and ineffective bargaining in the two years 1977 and 1978 at $4.9 billion.[2] This may be an understatement since the sample consisted of only 121 private utilities; there are over 120 other private utilities, many of which use FACs.

A more limited study of operation and maintenance expenditures was recently conducted by the Pennsylvania PUC.[3] It concluded that Pennsylvania members of the Pennsylvania-New Jersey-Maryland Power Pool could reduce cumulative production costs by $428 to $703 million over the period 1982 to 1987. It estimated that additional maintenance expenditures of $13

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2. David L. Kaserman and Richard C. Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," The Southern Economic Journal, vol. 48, no. 3 (January 1982), pp. 687-700.

3. Pennsylvania Public Utility Commission, Electric Power Plant Productivity Related to Plant Availability (December 1980).

million in 1982 could lead to production cost savings of $81 million to $128 million, or $6.30 to $9.80 in production costs per maintenance dollar.

THE FINANCIAL CONDITION OF ELECTRIC UTILITIES

The financial performance of electric utilities in the United States is one measure of how well the PUCs have succeeded in setting rates consistent with the principles of the Hope decision. Of course, the quality of management and the state of the economy are also important factors in financial performance. Indeed, the purpose of regulation is to make an adequate rate of return possible, but not to compel such a return under all circumstances.

Many electric utilities face financial problems today, not only because of dramatic changes in the economic environment of the industry during the 1970s, but also because of specific aspects of the regulatory environment. This section discusses the current financial condition of electric utilities, traces their progressive financial decline through the 1970s, and reviews the performance of the rate base method of regulation.

Recent History

During the 1960s, electric utilities successfully lowered their costs through scale economies (decreases in unit costs associated with larger operations) and technological advances. The average size of a new electric steam unit increased from 102 megawatts during the decade ending in 1960 to 203 megawatts during the decade ending in 1970. Currently, new units are from three to five times this size. Similar scale economies occurred in transmission networks. Technological advances during the 1960s included improved design of boilers, turbines, transformers, and transmission lines that permitted a decrease in per unit capital costs. There were no environmental controls in the 1960s on either sulfur dioxide emissions or solid waste disposal, and only minimal controls on particulate emissions. In that decade, electricity demand increased at a constant rate of about 7 percent annually, and construction time for new plants averaged two years. This environment made it easy to plan for capital expansion. As a result, the price of electricity for consumers dropped significantly during 1961-1966, and continued to drop during the 1967-1970 period of constant average costs. Table 1 shows the steady decline in average revenue per kilowatt hour sold from 1960 through 1970, adjusted for inflation.

It was in the interest of electric utilities to lower prices to consumers, since expanding sales meant increased profits. Table 1 shows the steady

TABLE 1. FINANCIAL STATISTICS OF ELECTRIC UTILITIES, 1960-1980

Year	Utility Earned Rate of Return on Equity (percent)	Allowed Return on Equity (percent) a	Earned Rate of Return Excluding AFUDC (percent)	Earned Rate of Return Total Manufacturing (percent)
1960	11.5	--	10.8	10.6
1961	11.6	--	11.1	9.9
1962	12.0	--	11.5	10.9
1963	12.2	--	11.8	11.6
1964	12.6	--	12.2	12.6
1965	12.9	--	12.4	13.9
1966	13.2	--	12.6	14.2
1967	13.1	--	12.2	12.6
1968	12.5	--	11.3	13.3
1969	12.5	--	10.9	12.4
1970	12.2	--	10.0	10.1
1971	12.0	--	9.4	10.8
1972	12.2	--	9.1	12.1
1973	11.8	--	8.6	14.9
1974	10.4	12.5	7.2	15.2
1975	11.5	12.9	8.3	12.6
1976	11.6	12.8	8.5	15.0
1977	11.5	13.1	8.0	14.8
1978	11.8	13.2	7.8	16.0
1979	11.4	13.4	6.8	18.3
1980	12.0	14.1	6.4	16.4

SOURCES: Duff and Phelps, Inc. (earned return on equity); Edison Electric Institute (allowed return on equity, AFUDC as a percent of net income, and average revenue per kilowatt hour); CBO (earned return excluding AFUDC); Citibank, Economics Department (earned rate of return manufacturing); Moody's Public Utility

increase in the rate of return that occurred from 1960 through 1966, due in part to the fact that during the period costs continually declined after rates were set. Since lowering the earned rate of return required initiation of a full rate case hearing, a natural inertia on the part of state PUCs allowed electric utilities to retain excess profits as capacity expanded and electricity costs fell. Rate-of-return reviews by state PUCs during the 1961-1968 period averaged only five per year. In contrast, 52 reviews were conducted

TABLE 1. (Continued)

Bond Yields (percent)	AFUDC as a Percent of Net Income	Real Average Revenue per Kilowatt Hour Sold (1980 dollars)[b]	Cost (1980 dollars)[b]	Year
4.84	5.7	4.70	3.95	1960
4.70	4.6	4.66	3.91	1961
4.44	4.3	4.52	3.77	1962
4.39	3.6	4.38	3.64	1963
4.56	3.6	4.22	3.51	1964
4.68	3.7	4.05	3.36	1965
5.61	4.8	3.86	3.21	1966
6.01	6.6	3.72	3.10	1967
6.72	9.3	3.52	2.95	1968
7.99	12.9	3.33	2.80	1969
8.85	17.8	3.26	2.74	1970
7.71	21.8	3.29	2.79	1971
7.46	25.1	3.30	2.80	1972
7.88	26.7	3.31	2.84	1973
9.21	31.0	3.86	3.49	1974
9.76	28.2	4.15	3.77	1975
8.80	27.1	4.18	3.90	1976
8.38	30.3	4.36	4.08	1977
9.22	33.9	4.37	4.11	1978
10.64	40.1	4.35	4.14	1979
13.09	46.3	--	4.53	1980

Manual, 1981, vol. 1 (bond yields); U.S. Department of Energy, Energy Information Administration, Statistics of Privately Owned Electric Utilities (costs).

a. Data not available before 1974. b. Cents per kilowatt hour.

in 1972 alone. Ninety percent of all electric utilities had only two or fewer formal rate hearings in the period 1958-1972. Many utilities now have such a hearing annually.

The rate of return earned by utilities began to decline after the late 1960s as the cost reductions associated with increased scale were exhausted. Since profits were high, many utilities were able to tolerate this. But when cost of service began its long-term upward trend, many companies were not able to earn their allowed rates of return. Consequently, the number of rate cases increased dramatically, beginning in 1968 and 1969.

The number of formal rate-of-return hearings continued to increase in the 1970s, and their processing time (or regulatory lag) also increased. General inflation, which took hold in the late 1960s, persisted throughout the entire decade of the 1970s. This, combined with regulatory lag, continually squeezed electric utility profits until a substantial and increasing number were unable to earn their allowed rates of return. In addition, the cost of financing began to rise sharply. The average cost of common equity rose from 6 percent during the 1960-1970 decade to 11 percent in the 1970-1975 period. Table 1 shows that bond yields--the cost of debt financing--rose from 4 or 5 percent in the early and middle 1960s to 9 or 10 percent in the late 1970s and 13 percent in 1980.

A variety of factors combined during this period to increase utility capital costs. The most important of these was the exhaustion of scale economies. Contrary to the experience of the early 1960s, generating costs no longer declined as the size of utility operations expanded. Further cost increases arose from chronic delays in capacity additions. Frequently these were nuclear. A delay in the licensing of a nuclear power plant, for example, could increase the capital costs of that plant by $6 million per month.[4] For coal plants, the passage of the Clean Air Act Amendments of 1977, and subsequent regulations, required strict sulfur dioxide, particulate, and solid waste controls. It added approximately 20 to 30 percent to the capital costs of a new coal plant with its requirement of flue gas desulfurization (scrubbing) and particulate control equipment. These environmental costs had not previously been confronted. Finally, inflation in the construction industry was generally more rapid than in the economy as a whole, further adding to the capital costs of power plants.

The Response of the Regulatory Process

State PUCs were able to satisfy both consumer and producer interests during the 1960s. Consumers were content with declining electricity prices, while producers gained from increasing returns to scale. When these circumstances changed during the 1970s, both groups became increasingly discontent.

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4. Congressional Budget Office, Delays in Nuclear Reactor Licensing and Construction: The Possibilities for Reform, Background Paper (March 1979).

Electric utilities, unable to earn their authorized rate of return, initiated many rate cases. In addition, with the advent of the 1970 Clean Air Act, environmental concerns were incorporated into the regulatory process. The constant interaction of these three groups--utilities, consumers, and environmentalists--in an ongoing inflationary environment confronted state PUCs with the need for new decisions. To deal with the unprecedented inflation rate, the PUCs now had to consider each element of the revenue requirement formula discussed at the outset of this chapter. Questions of whether to calculate the cost of capital equipment at its historical rate or at its substantially higher replacement cost, whether or not to use projected test periods, what accounting technique to utilize, and how to design fuel adjustment clauses, all became contentious issues.

In general, the state PUCs were slow to adapt their regulatory practices to these unprecedented circumstances. Projected test periods were not widely adopted, nor was the replacement or reproduction cost method of rate base valuation. Regulatory lag, the time associated with the processing of a formal rate case, increased with the dramatic growth in rate cases. In the inflationary environment of the 1970s, electric utilities typically experienced a significant difference between their anticipated revenue requirements and the larger amounts later found necessary. While this was partly attributable to less-than-anticipated demand, much of it resulted from regulatory lag that prevented utilities from fully recouping required revenues. The result was that many encountered increasing difficulty in earning their allowed rate of return, and their cash flow was impeded. Table 1 shows the increasing discrepancy between earned and allowed rates of return on common equity after 1975. By 1980, the differential was two percentage points.

The earnings of utilities were also affected by growing use of the AFUDC account. Rather than allowing new and unfinished investment (construction work in progress) to enter the rate base, many regulatory commissions sequestered it in AFUDC "promissory notes" instead. AFUDC income has increased dramatically as a percent of net income, from 17.8 percent in 1970 to an estimated 46.3 percent in 1980. Since AFUDC income is only accounting money, it reduces the cash available for interest payment and stock dividends and thus diminishes the quality of utility earnings. As can be seen in Table 1, when AFUDC accounts are excluded from the calculation of earnings, utilities earn a much lower rate of return. In 1972, for example, utilities earned a 12 percent rate of return, approximately equal to the rate earned by all manufacturing. Yet, when corrected for AFUDC, utilities' earnings dropped to slightly over 9 percent. By 1980, utilities earned a 12 percent rate of return, but only 6.4 percent if AFUDC is excluded. In contrast, the rate of return for all manufacturing in 1980 was over 16 percent.

The willingness or unwillingness of PUCs to grant rate relief are only one aspect of the regulatory problem in financing utility investment. Another is the increased sensitivity to the environmental costs and risks associated with coal-fired and nuclear plants, which has contributed to the increased time required to plan, site, and construct a generating facility (from an average of four or five years in the 1960s to about twelve years today). Longer construction periods, and the general unwillingness of PUCs to include CWIP in the rate base, require the utilities to borrow more per dollar of construction, raising the financing costs for every investment project.

CHAPTER III. INEFFICIENCY IN THE ELECTRIC UTILITY SECTOR

A rapidly changing business environment and the slow adaptation of many regulatory practices have contributed to the general financial decline of electric utilities and their diminished ability to make economic capital expenditures. This inability may affect the efficiency with which electricity is produced and, in turn, the composition of fuels used in the economy. The potential inefficiency may reveal itself through one of two effects: an incorrect use of fuels in generating, and a failure to construct enough new capacity.

With regard to fuel choice, electric utilities may continue to carry a considerable amount of oil- and gas-fired capacity that is uneconomic under a reasonable range of assumptions regarding future fuel prices and interest rates. This suggests that installations may not be configured to produce electricity in the least-cost fashion. With regard to the construction of new capacity, regulators have often held the rate of return allowed utilities to a level below the cost of new capital. If electricity demand grows substantially in the 1980s and capacity additions are slow to occur, generating capacity reserve margins could drop precipitously in many regions of the country.

These two problems--the problem of incorrect fuel choice dictated by existing plant, and the problem of inadequate generating capacity--are essentially a single problem. In order to avoid serious power shortages, utilities and their corresponding public utility commissions (PUCs) have the option of calling up generating units that would otherwise be inappropriate for baseload generation: peaking units, units slated for retirement, or reserve capacity in other regions (whose power would be transferred, or wheeled, into the relevant region). But most of these backup sources of generating capacity rely on oil or gas. Thus the result of inadequate generating capacity would not be blackouts, but increased use of otherwise uneconomic fuels.

This chapter examines the costs imposed on the economy by an incorrect utility fuel mix. It first presents data on the fuel composition of the utility generating stock and its regional breakdown. It then discusses the comparative costs of oil- and gas-fired generation and its major alternative, the use of coal. Finally, it provides projections of the utility fuel mix under alternate scenarios of electricity supply and demand, and estimates the extra cost burden imposed on the economy by inappropriate baseload generating capacity.

PATTERNS OF UTILITY FUEL USE

Electric utilities consumed the equivalent of 2.8 million barrels per day of oil and natural gas in 1981. By 1990, the use of these fuels is projected to decline to 1.9 million barrels per day. Nevertheless, over half of that use may still be uneconomic.

The expansion of electric power output in the past three decades has drawn heavily on primary energy sources. In 1949-1980, energy used in electricity production more than doubled as a percent of total U.S. energy consumption. As Table 2 shows, electric utilities accounted for 33.3 percent of total domestic energy consumption in 1981. Table 3 shows the percentage of total generation accounted for by each fuel type in 1981. Coal was by far the most important fuel, producing 52.4 percent of total electricity generated. Natural gas and oil produced 15.1 percent and 9.0 percent, respectively, and hydroelectric units 11.4 percent, of total electricity generated in that year. Nuclear energy provided 11.9 percent. Table 3 also translates these figures into oil equivalents. Utilities used about 1.0 million barrels a day in residual fuel oil to produce electricity in 1981. Utility natural gas use was equal to 1.6 million barrels of residual fuel oil per day. Together oil and gas produced nearly 24 percent of total electricity generated in 1981, or the equivalent of 2.6 million barrels per day of oil. This figure represents approximately one-half of net oil imports, and 18 percent of total petroleum products supplied in that year. Thus, as compared to other alternatives for reducing oil imports, displacing oil and natural gas in the utility sector may be an attractive option.

Utility fuel use varies among the nine regions defined by the National Electricity Reliability Council (Figure 1). As may be seen in Table 4, the Northeast is by far the most oil-reliant of all regions, depending on that fuel for 44 percent of its electricity. The Mid-Atlantic region uses oil to produce 23 percent of its electricity. Oil use is substantial in the Southeast (14 percent), and particularly in Florida (49 percent). The West is reliant on both oil (16 percent) and natural gas (14 percent). Texas relies on natural gas for 72 percent of its primary fuel input and the Southwest region relies upon natural gas for 61 percent of its primary fuel input. Other regions depend predominantly on coal.

THE ECONOMICS OF OIL AND GAS REPLACEMENT

Generating capacity is of three distinct kinds. The first is baseload capacity. Because baseload units produce the least costly electricity when run at high capacity factor, they are relied upon most heavily to meet demand. Those that are fueled with coal or uranium have high capital

TABLE 2. INSTALLED GENERATING CAPACITY AND ENERGY CONSUMPTION OF THE ELECTRIC UTILITY INDUSTRY, SELECTED YEARS (1949-1980)

	Capacity (millions of kilowatts)							Energy Consumption (quadrillions of Btus)		
									Electric Utilities	
Year	Conventional Steam[a]	Hydropower	Internal Combustion	Gas Turbine	Nuclear Power	Geothermal	U.S. Total	U.S. Total	Total	As Percent of U.S.
1949	44.6	16.7	1.8	--	--	--	63.1	31.08	4.66	15.0
1950	49.3	17.7	1.9	--	--	--	68.9	33.62	5.02	14.9
1955	87.1	25.0	2.4	--	--	--	114.5	39.17	6.79	17.3
1960	132.1	32.4	2.8	--	0.3	--[b]	168.0	44.08	8.23	18.7
1965	186.6	43.8	3.4	1.4	0.9	--[b]	236.1	52.99	11.07	20.9
1970	260.0	55.1	4.4	15.5	6.5	0.1	341.6	66.83	16.29	24.4
1971	277.8	55.9	4.5	21.9	8.7	0.2	368.9	68.30	17.22	25.2
1972	294.1	56.4	4.8	27.7	15.3	0.3	398.6	71.63	18.58	25.9
1973	320.6	62.0	5.0	33.4	21.0	0.4	442.4	74.61	20.01	26.8
1974	337.3	63.6	5.0	39.6	31.6	0.4	477.6	72.76	20.16	27.7
1975	352.9	65.9	5.1	44.1	39.8	0.6	508.3	70.71	20.42	28.9
1976	367.9	67.7	5.3	46.6	42.9	0.6	531.0	74.51	21.55	28.9
1977	387.8	68.7	5.3	47.9	49.9	0.6	560.2	76.33	22.82	29.9
1978	399.5	71.0	5.5	49.0	53.5	0.6	579.2	78.18	23.55	30.1
1979	411.6	75.3	5.5	50.6	54.6	0.7	598.3	78.91	24.14	30.9
1980	423.5	76.4	5.5	50.6	56.5	1.0	613.5	75.91	24.44	32.2
1981[c]	438.6	77.1	5.6	51.4	60.7	1.0	634.5	73.91	24.63	33.3

SOURCE: Energy Information Administration, Annual Report to Congress (1981), vol. 2.
NOTE: Sum of components may not equal total due to independent rounding.

a. Excludes geothermal. b. Less than 0.05 million kilowatts. c. preliminary.

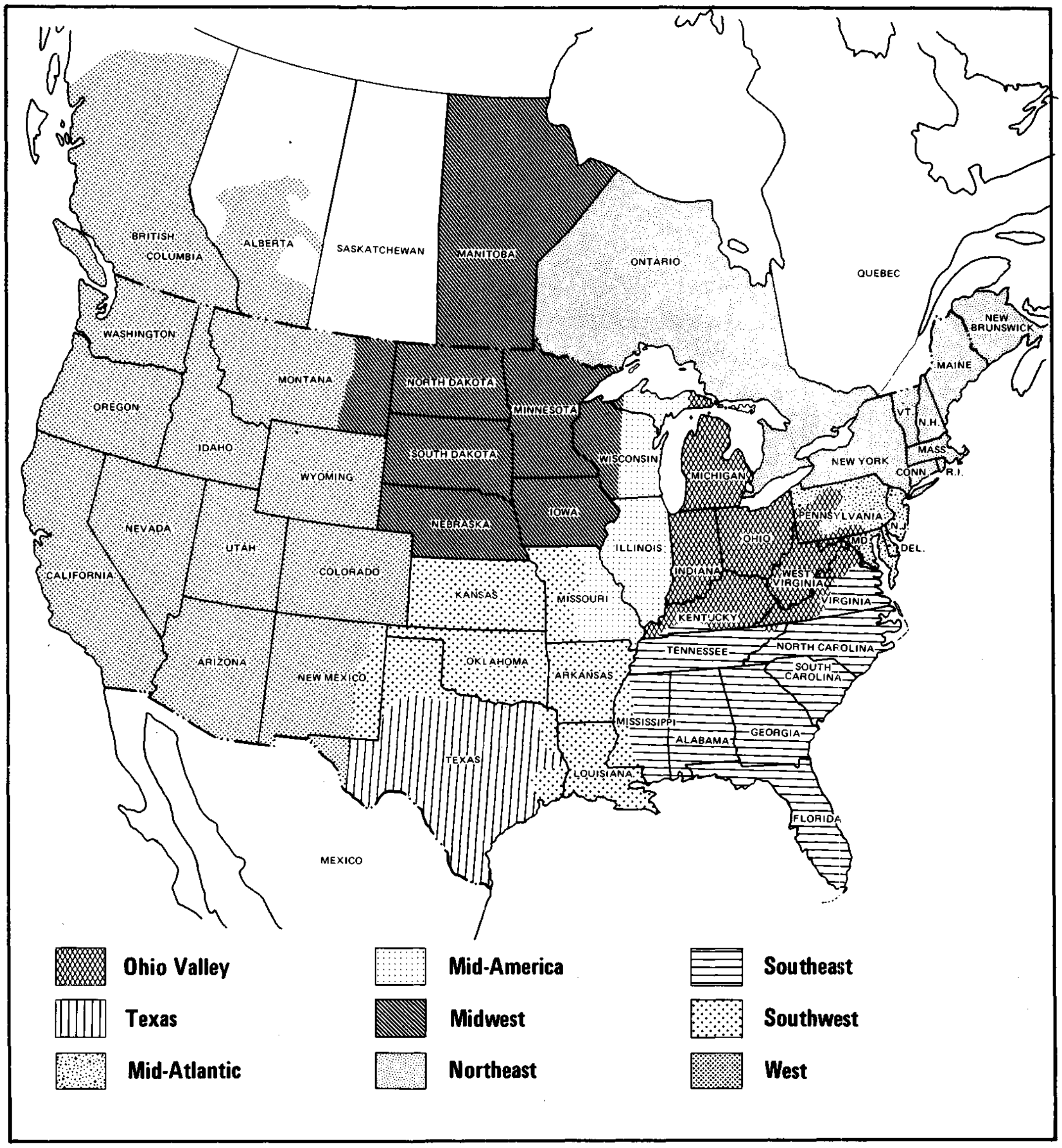
TABLE 3. ENERGY CONSUMED AND PRODUCED BY ELECTRIC UTILITIES, 1981

Unit of Measurement	Coal	Natural Gas	Oil	Hydro-electric Power	Nuclear Electric Power	Other	Total
Millions of Kilowatt Hours Produced	1,203,203	345,777	206,421	260,684	272,674	6,054	2,294,812
Primary Energy Consumed	596,797 (thousands of tons)	3,640,154 (millions of cubic feet)	351,111 (thousands of barrels)				
Percent of Generation	52.4	15.1	9.0	11.4	11.9	0.3	—
Residual Oil Equivalent Consumed (thousands of barrels per day)[a]	5,675	1,631	962.0	1,230	1,286	29	10,813

SOURCE: Monthly Energy Review (April 1982).

a. Calculated at 6.2 million Btus per barrel.

Figure 1.
National Electric Reliability Council



NOTE: The National Electric Reliability Council (NERC) was formed in 1968 to "augment the reliability and adequacy of bulk power supply in the electric utility systems of North America." It consists of nine Regional Reliability Councils and encompasses essentially all of the power systems of the United States as well as Canadian systems in Ontario, British Columbia, Manitoba, New Brunswick and Alberta.

TABLE 4. PERCENTAGE OF ELECTRICITY PRODUCED IN EACH NATIONAL ENERGY RELIABILITY COUNCIL (NERC) REGION, BY PRIMARY ENERGY INPUT, 1979

	Ohio Valley	Texas	Mid-Atlantic	Mid-America	Mid-west	North-east	South-east	South-west	West	Total U.S.
Nuclear	5.3	--	19.8	20.8	21.6	24.0	16.4	2.3	4.2	11.6
Coal	90.0	26.4	51.8	70.7	56.6	11.7	56.3	20.1	25.1	48.2
Oil	4.5	1.5	22.8	4.9	1.1	44.1	13.7	11.6	16.1	13.6
Gas	0.2	71.9	3.5	2.0	1.6	4.0	3.8	60.8	14.2	14.1
Hydro	0.9	0.2	3.9	1.4	14.6	17.8	10.3	1.0	40.4	12.7
Geothermal and Other	--	--	--	0.2	--	--	0.1	4.0	0.2	0.4
Pumping Energy[a]	(0.9)	--	(1.8)	--	--	(1.6)	(0.6)	0.2	(0.2)	(0.6)

SOURCE: Martin L. Baughman, The Regional Economic Impacts on Electricity Supply of the Powerplant and Industrial Fuel Use Act and Proposed Amendments (H.R. 6930 and S. 2470), Southwest Energy Associates, Incorporated (April 1980).

a. Energy used to allow storage of electricity.

charges, which must be spread over as much generation as possible, and low fuel costs. For this reason, baseload plants are called upon first to meet load and operated at as high a capacity factor as possible.[1] Peaking units, the second type of generating capacity, are usually employed to meet daily or seasonal peak demands, for example during evening hours. Typically, these units are oil- or gas-fired turbines that have low capital costs and can be started up quickly. Because they are peaking units, their average capacity utilization rates are lower. Between baseload and peaking units is a midrange of plants that share some of the characteristics of both baseload and peaking units, often termed intermediate capacity.

Oil and gas remain attractive fuels for peaking purposes for two reasons. First, there are technical difficulties in making abrupt changes in load with coal- or nuclear-powered stations. Second, and perhaps more important, generating stations that burn oil or gas generally have low capital costs per kilowatt. Thus they can be used intermittently without imposing an unacceptable fixed-charge burden on the electricity they generate. Of course, pricing practices that reduce peak loads can result in the economic displacement of some oil and gas capacity, but the amount is likely to be small. More important, the bulk of oil and gas consumption occurs in generating units that service base and intermediate loads. Therefore, significant reductions in oil and gas consumption in the utility sector can only come through changes in the baseload fuel mix.

Recent history suggests a low rate of growth in nuclear baseload capacity in coming years. Thus, coal presumably will be the chief alternative in replacing oil and gas over the next decade. This implies that reducing utility oil and gas consumption will require either the reconversion of existing oil-fired, but coal-capable, units or the accelerated construction of new coal-fired units.

Many oil- and gas-fired units were converted from coal-fired units for environmental reasons before the runup in the price of oil. These units can be reconverted to coal. Other oil- and gas-fired units would have to be retired rather than reconverted. The economics of oil and gas replacement, therefore, involves a comparison of the costs of reconverting coal-capable oil- and gas-fired units and of accelerating construction of new coal-fired units to the costs of continuing to operate oil-fired units. The estimates that follow are based on two alternative assumptions: a continuation of

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1. A plant's capacity factor is the ratio of the electric energy it actually produces to the maximum it theoretically could produce. For large baseload generating stations, it ranges from 55 to 65 percent.

current environmental policy on the one hand, and a stricter environmental scenario on the other.

Costs of Reconverting Existing Coal-Capable Units

It is estimated that approximately 21 billion watts (gigawatts) of oil-fired capacity once burned coal and could be reconverted back to coal. Half of this capacity is in New England, and an additional 21 percent is in the Mid-Atlantic states. Table 5 provides a regional assessment of the costs of reconversion under two different environmental scenarios. The first represents current environmental policy, meaning that some, but not all, units would require the installation of flue gas desulfurization equipment (FGD, or "scrubbers"). Under this standard, total conversion costs for 21 gigawatts of coal capacity are estimated at $5.77 billion in 1980 dollars. Regionally, conversion costs range from a low of $113 per kilowatt in the Southeast to $598 per kilowatt in the West. In New England and the Mid-Atlantic states, the costs range from $247 to $278 per kilowatt. Reconversion of the total 21 gigawatts of capacity would reduce utility oil and gas consumption by 350,000 to 400,000 barrels of oil equivalent per day.

A stricter environmental scenario would require the installation of FGD equipment on all converted units. This increases the estimate of total conversion costs to $9.5 billion, 65 percent higher than the first estimate. The application of FGD affects the regions differently, as seen in Table 5. In the Northeast, which has the greatest number of reconversions (11 gigawatts, or 52 percent of total national reconversions), estimated costs increase by only $95 per kilowatt, or 39 percent, to $342 per kilowatt. In the Mid-Atlantic region, however, costs increase from $278 per kilowatt to $663 per kilowatt--a 138 percent increase. The cost of reconversion in the Southeast remains the lowest under both scenarios. In the Ohio Valley region the requirement of FGD on all converted units raises the costs from $239 per kilowatt to $613 per kilowatt--a 256 percent increase. It should also be noted that the West currently requires FGD on all conversions (0.1 gigawatts), so that costs do not increase when more stringent environmental standards are applied. Generally, these costs increase to the extent that existing state air regulations are now lenient.

Fuel Cost Savings Compared with Reconversion Costs. Determining whether the capital costs of reconversion are offset by lower fuel costs requires assumptions about future oil, gas, and coal prices. Here it is assumed that oil and natural gas prices increase at an average rate of 4 percent per year faster than the rate of inflation from a base of $31 per barrel and $4 per million cubic feet in 1980, while coal prices rise 1 percent per year faster than inflation from a base of $36 per ton in 1980. These

TABLE 5. RECONVERSION COSTS OF COAL-CAPABLE GENERATING UNITS (All capacity to be converted by 1985)

Region	Capacity Converted (gigawatts) [a]	Costs Under Current Environmental Policy: Billions of 1980 Dollars	Costs Under Current Environmental Policy: Dollars per Kilowatt	Economic by 1985 [b]	Costs if Flue Gas Desulfurization Required: Billions of 1980 Dollars	Costs if Flue Gas Desulfurization Required: Dollars per Kilowatt	Economic by 1985 [b]
Ohio Valley	0.715	0.171	239	x	0.438	613	-
Texas	--	--	--		--	--	
Mid-Atlantic	4.482	1.246	278	x	2.973	663	-
Mid-America	1.599	0.560	350	-	0.820	513	-
Midwest	--	--	--		--	--	
Northeast	11.029	2.725	247	x	3.773	342	x
Southeast	1.909	0.215	113	x	0.597	313	x
Southwest	1.425	0.787	552	x	0.883	620	x
West	0.107	0.064	598	x	0.064	598	x
Total NERC	21.266	5.768	271		9.508	447	
Percent of Total Reconversions				93.3			68.0

SOURCE: Martin L. Baughman, The Regional Economic Impacts on Electricity Supply of the Powerplant and Industrial Fuel Use Act and Proposed Amendments (H.R. 6930 and S. 2470), Southwest Energy Associates, Incorporated (April 1980).

a. These units were selected by the Department of Energy, after taking into consideration technical feasibility, environmental standards, cost-effectiveness, and other cite-specific limitations.

b. Indicated as x if the reconversion results in fuel savings greater or equal to capital costs by 1985, and as - if not.

assumptions are taken not to reflect short-term fuel prices, which are lower, but to represent price trends over the life of new generating equipment, which would extend into the next century. These estimates assume the decontrol of natural gas in 1985. A rate of return on equity of 16 percent and a real interest rate on debt of 3 percent were also assumed. Under current environmental policy, fuel cost savings offset the estimated capital cost of conversion in all regions except Mid-America (see Figure 1). Under the stricter environmental scenario, costs are lower in the Northeast (which accounts for over one-half of reconversions) and Southeast by 1985. In the Southwest and West, capital costs and fuel savings are approximately equal. Capital costs exceed fuel savings in the Mid-Atlantic, Mid-America, and Ohio Valley regions. By 1990, the Mid-Atlantic region enjoys cost savings of nearly 4 percent, the Ohio Valley region has costs that are unaffected by conversion, and the Mid-America region still experiences cost increases. By 1995, however, this region has cost decreases.

Nearly 70 percent of the reconversions (15.5 gigawatts) occur in the Northeast and Mid-Atlantic regions. In the Northeast region, which presently relies on oil for 44 percent of its primary energy input, 1985 variable fuel costs are reduced by 4.5 times the capital costs of reconversion on an annuitized basis (or three times the costs of reconversion under the stricter environmental rules). In the Mid-Atlantic region, fuel savings are also substantial, but under the stricter environmental regulations they do not offset higher capital expenditures until 1990. The Mid-Atlantic is representative of most of the regions in that reconversions are economic, but their payback periods can be lengthened by up to five years if additional environmental quality is required. Opting for less environmental protection (retaining the current standards required by states) allows for earlier rate reductions when compared to continued reliance on oil and gas, while opting for greater environmental protection (through mandatory FGD) postpones such rate reductions until the 1990s. This analysis has not attempted to estimate the benefits associated with additional environmental protection.

The Economics of Accelerated Retirements

Even if all available oil- and gas-fired plants that once burned coal were reconverted to that fuel, over 120 gigawatts of oil- and gas-fired capacity would remain, as shown in Table 6. Thus, the accelerated retirement of these oil- and gas-fired units and their replacement by coal-fired units must be considered in any long-term effort to reduce oil and gas consumption in the electric utility sector. As Table 6 shows, the Southwest and Texas regions represent the largest targeted area for accelerated retirement, one that is predominantly reliant on natural gas. Potential retirements in this area by 1985 total 57.8 gigawatts, or 47 percent of all

TABLE 6. POTENTIAL COAL RECONVERSIONS AND OIL/GAS CAPACITY REMAINING, BY REGION (In gigawatts)

	Mid-Atlantic	North-east	South-east	West	South-west	Texas	Total
Oil-fired Capacity	14.0	25.2	17.8	24.9	9.0	--	90.9
Gas-fired Capacity	--	--	0.1	1.1	21.3	28.9	51.4
Total	14.0	25.2	17.9	26.0	30.3	28.9	142.3
Reconversions	4.5	11.0	1.9	0.1	1.4	--	18.9
Remaining Oil and Gas Capacity	9.5	14.2	16.0	25.9	28.9	28.9	123.4

SOURCE: Martin L. Baughman, The Regional Economic Impacts on Electricity Supply of the Powerplant and Industrial Fuel Use Act and Proposed Amendments (H.R. 6930 and S. 2470), Southwest Energy Associates, Incorporated (April 1980).

oil- and gas-fired capacity in the United States. Clearly the opportunity for accelerated retirement will be greatest here. The West, particularly California, is second in the number of potential retirements with 25.9 gigawatts. These three areas account for over two-thirds of possible accelerated retirements.

Table 7 compares the costs of operating an existing oil-fired plant with the costs of building and operating a new coal-fired plant. The comparison is made in five different areas having significant oil and gas capacity. Under current residual oil prices of $30 per barrel in 1980 dollars--the average price of residual oil purchased by utilities in the first six months of 1981 was approximately $34.00--and a real capital charge (in excess of inflation) of 10 percent, it is economic to construct a new coal-fired plant in Texas. The economic advantage of coal is marginal in Northern or Southern California and Northern Florida. The comparison is unfavorable for coal in the Northeast. If the real capital charge falls to 8 percent, because of lower interest rates or because the risks associated with

TABLE 7. COMPARISON OF THE OPERATING COSTS OF AN EXISTING OIL PLANT WITH THE ANNUALIZED COSTS OF A NEW COAL PLANT BY REGION AND UNDER ALTERNATIVE REAL CAPITAL CHARGE RATES (All figures in constant 1980 dollars)

	Existing Oil		New Coal Plant--By Region Texas		
	$30 per Barrel	$35 per Barrel	8 Percent	10 Percent	12 Percent
Capital Costs					
Initial Capital Cost (dollars per kilowatt)	--	--	1,285	1,285	1,285
Annualized Capital Cost (dollars per kilowatt)[a]	--	--	102.8	128.5	154.2
Annualized Capital Cost (mills per kilowatt-hour)[b]	--	--	18.1	22.6	27.1
Fuel Costs					
Average Fuel Cost (dollars per million Btus)	4.84	5.65	1.05	1.05	1.05
Heat Rate (Btus per kilowatt-hour)	9,340	9,340	11,048	11,048	11,048
Fuel Cost per Kilowatt-Hour (mills per kilowatt-hour)	45.2	52.8	11.6	11.6	11.6
Operation and Maintenance (mills per kilowatt-hour)	0.5	0.5	5.4	5.4	5.4
Total Cost (mills per kilowatt-hour)[c]	45.7	53.3	35.1	39.6	44.1

SOURCES: G. Martin Wagner, Substituting Coal Power Plants for Oil Plants, memorandum, United States Environmental Protection Agency (November 21, 1980); and the Congressional Budget Office.

a. Annualized capital costs in dollars per kilowatt are derived by multiplying the initial cost by the real capital charge rate.

TABLE 7. (Continued)

New Coal Plant--By Region											
Northern Florida			Northeast			Northern California			Southern California		
8 Percent	10 Percent	12 Percent	8 Percent	10 Percent	12 Percent	8 Percent	10 Percent	12 Percent	8 Percent	10 Percent	12 Percent
1,078	1,078	1,078	1,235	1,235	1,235	1,200	1,200	1,200	1,237	1,237	1,237
86.2	107.8	129.4	98.8	123.5	148.2	96	120	144	99.0	123.7	148.4
15.1	18.9	22.7	17.4	21.7	26.0	16.9	21.1	25.3	17.4	21.7	26.1
2.20	2.20	2.20	2.20	2.20	2.20	1.85	1.85	1.85	1.75	1.75	1.75
10,009	10,009	10,009	9,957	9,957	9,957	10,143	10,143	10,143	10,143	10,143	10,143
22.0	22.0	22.0	21.9	21.9	21.9	18.8	18.8	18.8	17.8	17.8	17.8
5.0	5.0	5.0	5.4	5.4	5.4	5.5	5.5	5.5	7.3	7.3	7.3
42.1	45.9	49.7	44.7	49.0	53.3	41.2	45.4	49.6	42.5	46.8	51.2

b. Annualized capital costs in mills per kilowatt-hour are derived by dividing costs in dollars per kilowatt by 5,694 (the total hours of generation per year assuming a capacity factor of 65 percent) and multiplying this quotient by 1,000.

c. Total costs vary directly with the interest rate. They are the sum of annualized capital cost, fuel cost, and operation and maintenance costs.

adding new capacity fall, then it becomes economic to build a new coal-fired plant in all the selected regions with oil prices at $30 per barrel. On the other hand, if interest rates continue to rise or the risks of adding new capacity persist unabated and the real capital charge rate increases to 12 percent, then only in Texas is it economic to construct a new coal-fired plant. Finally, if the price of oil increases at a real rate of 0.9 percent per year to $35 per barrel in 1990 (in 1980 dollars) then it becomes economic to construct a new coal-fired plant in all selected regions under all three capital charges.

Substituting Coal for Oil and Gas: How Much Is Enough?

The foregoing discussion has demonstrated that utilities could eliminate much oil and gas use by substituting coal, resulting in a cost saving if oil prices rise from current levels. Indeed, several utilities are already doing so by reconverting coal-capable units. But there is reason to believe that the rate at which substitution is proceeding is less than would be suggested by economic considerations alone.

Of course, a complete and instantaneous movement toward coal substitution should not be expected, and indeed is not suggested by purely economic considerations. As shown in Table 7, coal use may be marginally economic in some areas and uneconomic in others, depending upon the assumptions chosen. This is particularly true for retirements of existing oil and gas units that are not coal-capable. As Table 7 also shows, oil and gas unit retirements may be strongly influenced by capital charges. Thus, uncertainty over interest costs can lead management to delay coal conversion activities.

Relative fuel prices also influence the economic viability of switching to coal. As seen in Table 7, virtually all retirements of baseload oil and gas are economic when oil prices reach $35 per barrel (in 1980 dollars). At their current level, however, of $30 per barrel, this is not the case. The Department of Energy recently estimated the proportion of total oil and gas use that would remain economic at various fuel prices.[2] At $30 per barrel, 41 percent of oil and gas use by utilities was estimated to be cost-effective (much of this in peaking uses). At $40 per barrel, the proportion dropped to 23 percent. Similarly, a recent study by the Environmental Protection

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2. U.S. Department of Energy, Reducing U.S. Oil Vulnerability: Energy Policy for the 1980s, prepared by the Assistant Secretary for Policy and Evaluation (November 10, 1980).

Agency examined the sensitivity of the utility fuel mix to coal prices.[3] Using a base case in which coal prices rose at a compounded rate of 2 percent in real terms annually from 1980 to 2020 (with annual increases declining from 5 percent in the early 1980s to 1.7 percent in the next century), coal was found to remain economic for electricity generation. A compounded rate of 3.5 percent (with annual increases of 5 percent throughout the 1980s and 3 percent thereafter) eliminated coal's cost advantage. Given the myriad of factors that influence delivered coal prices, including rail rates, severance taxes, and environmental costs, many utilities may hesitate to make strong commitments to coal.

Fuel prices, interest rates, and uncertainties in demand all stand as inhibiting factors in the movement toward coal substitution in utilities. Moreover, it should be noted that cost estimates involve "prototypical" plants, and thus might not apply to any particular situation. Some plants will have greater difficulty in switching to coal because of site-specific limitations such as proximity to populated areas, or land constraints that make coal storage or the installation of environmental equipment impractical.

Despite these caveats, there is reason to believe that the current rate of coal substitution is less than would obtain if economic considerations were to dominate fuel choice. This can be ascribed to the effects of several of the regulatory procedures described in Chapter II, particularly those that may serve to bias a utility away from making capital expenditures on new plants. Among these features are the use of AFUDC instead of immediate recoupment of construction work in progress, the use of fuel adjustment clauses allowing the automatic passthrough of higher oil and gas costs, and the determination of allowed rates of return that are lower than the cost of new capital. These regulatory procedures may slow the utility industry's conversion to coal; to the extent that they do so, the economy as a whole will bear the costs in lower efficiency. These costs are examined below.

INEFFICIENCY COSTS IN THE ELECTRIC UTILITY SECTOR

Inefficiency costs in the electric utility sector are borne by the economy as a whole, since more resources must be diverted to pay for

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3. U.S. Environmental Protection Agency, "An Economic Evaluation of the Replacement of Oil-Fired Generation Capacity with Coal-Fired Capacity," prepared for the Energy Policy Division, Office of Planning and Evaluation, by Putnam, Hayes, and Bartlett, Incorporated, Cambridge (March 1981).

electricity than would otherwise be the case. These extra production costs depend on the levels of electricity supply and demand, particularly the former. Should new baseload generating capacity not keep pace with demand, utilities and their PUCs will be forced to call up retired units, use peaking and intermediate units at higher capacity factors, and wheel in excess power from adjacent regions. These sources of additional power are predominantly oil-and gas-fired, and hence tend to be uneconomic.

Inefficiency costs also pose a direct danger for electric utilities. As electricity prices rise to reflect these inefficiency costs, electricity consumption will certainly drop below levels that would have been obtained with a least-cost configuration. This demand effect may be sufficiently strong that utilities would be left with less revenue than they would have received had they expanded their capacity along least-cost lines. (In economic terms, the demand for electricity may be elastic.) This would lower utility profits and cash flow. Some utilities might then be forced to seek still higher rates to recoup their losses, perpetuating the downward spiral of sales. Moreover, as utility cash flow, sales, and profits decreased, both the impetus and ability to make new cost-saving investments would decrease, exacerbating the problem further. Thus, inefficiency costs may trigger a downward spiral of electricity sales and lead to even larger economic losses.

Costs of Incorrect Fuel Choice

Table 8 presents estimates of utility oil and gas consumption by electric utilities in the year 1990; these projections provide a basis for estimating the inefficiency costs associated with inappropriate oil and gas consumption. They reflect the assumption that 196 gigawatts of capacity are added between 1981 and 1990.

As seen in Table 8, utility oil and gas consumption is projected to be 1.9 million barrels per day in 1990. Not all of it, however, would be used for baseload generation. The proportion of oil and natural gas used for baseload generation has declined steadily throughout the 1970s. Assuming that 40 percent of both oil and gas would still be used for baseload generation in 1990, uneconomic oil and gas use would result in excess annual electricity costs of $1.5 billion in 1980 dollars, or $2.1 billion in 1990 dollars.

Costs of Inadequate Capacity

Tables 8 and 9 provide a basis for comparing the inefficiency costs of using excess oil and gas for electricity production in the year 1990. Table 8

TABLE 8. PROJECTIONS OF DEMAND AND CAPACITY GROWTH OF OIL AND GAS CONSUMPTION IN THE ELECTRIC UTILITY INDUSTRY, 1981-1990

	Average Annual Demand Growth, 1981-1990 (percent)	Capacity Additions, 1981-1990 (gigawatts)	Reserve Margin (percent)	1990 Oil and Gas Consumption (thousands of barrels per day)
Texas	4.6	55.98	18	403
Gulf States	3.7	35.35	27	202
Missouri/Kansas	3.8	15.70	24	17
Oklahoma	4.0	22.14	20	98
California/Nevada	2.7	58.74	16	314
Florida	3.8	30.54	15	249
New England	2.8	26.29	28	109
Mid-Atlantic	2.8	52.31	29	116
New York	1.3	32.59	37	147
Virginia/Carolinas	3.8	51.09	26	19
Arizona/New Mexico	5.8	19.92	42	18
Ohio Valley	3.6	119.3	33	54
Mid-America	3.2	54.33	24	29
TVA/Southern	3.1	76.01	38	24
Rocky Mountain	5.9	10.95	28	5
Northwest	4.5	58.10	40	94
Midwest	4.2	33.44	24	27
Total United States	3.5	200.49	30	1,918

SOURCE: Los Alamos National Laboratory, Electric Utility Oil and Gas Use in the Eighties, LA-9319-MS (April 1982).

presents a base case, under which oil and gas consumption is projected as the combined equivalent of 1.9 million barrels per day. Table 9 presents an estimate of oil and gas consumption under a case in which new-capacity additions drop by one-third below those in Table 8 and in which oil and gas consumption rise to the equivalent of 3.2 million barrels per day. Thus, a 33 percent reduction in new capacity translates into a 67 percent increase in oil and gas burning by utilities. If real oil prices remain at $30 per barrel in this decade, excess electricity production costs would be $3.0 billion in 1980

TABLE 9. POTENTIAL INEFFICIENCY COSTS IN 1990 UNDER A REDUCED RATE OF NEW CAPACITY

	Reduction in Capacity (gigawatts)	Reserve Margin (percent)	Oil and Gas Consumption (thousands of barrels per day)	Increase in Oil and Gas Consumption Over Base Case (thousands of barrels per day)	Estimated Excess Production Costs (oil price at $30 per barrel, in millions of 1980 dollars)	Estimated Excess Production Costs (oil price at $35 per barrel, in millions of 1980 dollars)
Texas	6.59	15	594	191	649.3	988.0
Gulf States	5.29	21	351	149	503.7	767.6
Missouri/Kansas	1.93	15	23	6	11.5	22.1
Oklahoma	2.60	16	170	72	137.2	264.7
California/Nevada	10.00	15	608	294	564.2	1,085.0
Florida	3.73	15	358	109	209.2	402.3
New England	3.44	21	195	86	118.4	227..7
Mid-Atlantic	1.74	27	149	33	45.4	87.4
New York	1.71	30	197	50	68.8	132.2
Virginia/Carolinas	2.80	24	34	15	28.8	55.4
Arizona/New Mexico	1.98	28	30	12	22.0	42.4
Ohio Valley	6.87	28	87	14	26.9	51.7
Mid-America	2.80	19	37	8	15.4	48.1
TVA/Southern	.68	37	24	0	0	0
Rocky Mountain	2.68	15	67	62	186.7	359.1
Northwest	6.55	36	212	118	355.3	683.4
Midwest	4.77	15	61	34	65.2	125.4
Total United States	66.18	18	3,197	1,279	3,008.0	5,322.2

SOURCE: Los Alamos National Laboratory, Electric Utility Oil and Gas Use in the Eighties, LA-9319-MS (April 1982); and Congressional Budget Office.

dollars. Should oil prices rise to $35 per barrel, the costs would increase to $5.3 billion. Both estimates, it should be noted, are for the year 1990 only.

Analyzing the low-supply case geographically, the bulk of the increased oil and gas consumption (1.0 out of the 1.3 million barrels per day increase) would be attributable to the current seven largest oil and gas consuming areas. The largest increase would occur in the Texas, California/Nevada, Gulf States, and Oklahoma regions.

The inefficiency costs are based on the estimated differential between using oil and gas on one hand or coal on the other hand in baseload generation. Areas that incur inefficiency costs do so through the uneconomic baseload use of oil and gas. For the purposes of these estimates, the average real cost of coal-fired power is 42 mills per kilowatt hour, while oil-fired units cost 51.3 mills per kilowatt hour assuming a capacity factor of 65 percent, a heat rate of 10,500 Btus per kilowatt-hour, and oil prices of $30 per barrel in 1980 dollars (or approximately $54 per barrel in 1990 dollars). In addition, uneconomic production can occur if supply reductions endanger reliability levels so that oil or gas peaking units must be constructed or called up. The cost differential between peaking oil- and gas-fired units and coal or nuclear baseload costs is even greater than the difference between coal-fired and oil- or gas-fired baseload costs. The model used to make these estimates assumed that regional reserve margins would not drop below 15 percent (implying the construction of peakers to maintain this reliability level.)[4] This margin is found in five of the seven most oil- and gas-reliant regions (the New England and New York regions have considerable reserve margins in both cases), where the bulk of oil and gas is still used for baseload and intermediate purposes.

These estimates of excess production costs are conservative, for three reasons. First, they do not include the production inefficiencies accompanying oil and gas consumption in the base case. Since utilities are financially constrained on the whole, many have planned capacity additions that merely meet anticipated load growth and do not accelerate the retirement of existing oil and gas units. In some cases, analysts suspect that the load growth figures may even be purposefully underprojected so that the utilities will not be forced to construct new plants. In any event, a rough estimate of uneconomic oil and gas use can be made for the base case. In relation to total oil consumption in electricity production, baseload oil consumption declined from around 65 percent in 1973 to 44 percent in 1978, while baseload gas consumption remained relatively stable at approximately 60

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4. Los Alamos National Laboratory, Electric Utility Oil and Gas Use in the Eighties (April 1982), p. III-18.

percent. Intermediate and baseload consumption combined accounted for roughly 85 percent of all oil and gas consumption in 1978. It may be assumed that baseload oil use will continue to decline, while natural gas will continue to be used primarily in baseload. Thus, even if only 40 percent of the total projected 1.9 million barrels per day of oil and gas use in 1990 under the NERC base case occurs in baseload use, this implies excess electricity production costs in 1990 of nearly $1.5 billion in 1980 dollars, or $2.1 billion in 1990 dollars.

Second, the low-supply case may not be low enough. It assumes that all the units currently under construction are completed on schedule. In the months after the NERC study was issued, a number of coal and nuclear units were cancelled or deferred indefinitely. Among them were plants under construction that the study had assumed would be completed for its low-supply case. These cancellations and deferrals (in conjunction with potential additional cancellations throughout this decade), especially in areas where reserve margins are low, imply additional uneconomic oil and gas use in baseload, intermediate, and peaking modes, and a decline in reliability reserve margins.

Finally, these excess production cost figures assume that oil prices rise only with inflation, which was not the case during the 1970s. If oil prices were to rise in real terms to $35 per barrel in 1990 ($62.65 in 1990 dollars), excess production costs (as shown in column 6 of Table 9) could total $5.3 billion (or $9.4 billion in 1990 dollars, assuming the same inflation rate).

Moreover, these excess production cost figures cover only one year, 1990. Inefficiencies would mount over the decade under the low-supply scenario in which new capacity additions drop by a third. The Los Alamos study has provided an estimate of cumulative losses over the entire decade. It is based, however, on rapid rises in oil and gas prices, and therefore, is most likely an overestimate.[5]

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5. Ibid. Over $33 billion extra in revenue is required under the low-supply case, with the greatest losses in the most oil- and gas-reliant areas. These losses amount to over $9 billion in California, $4.5 billion in Texas, over $4 billion in the Gulf States region, $3.4 billion in Florida, and $1.7 billion in both New England and New York State. The Northwest losses total $4.7 billion, while the Rocky Mountain region loses $1.6 billion. It should be noted that more coal-reliant areas (like the Mid-America and Mid-Continent regions) actually require less revenue under a reduced-supply case in that they would (Continued)

Effects Beyond 1990

If delays in adding new capacity continued beyond 1990, they would extend the uneconomic use of oil and gas and further reduce reserve margins. A recent study estimated the effects of such constraints if continued through 1995.[6] If coal-fired and nuclear capacity additions were limited to 108 gigawatts and 76 gigawatts respectively through 1995, oil and gas use would increase from a projected 0.6 million barrels per day in 1995 to over 2.9 million barrels per day. In other words, a 40 percent reduction in capacity additions (from 309 gigawatts to 184 gigawatts through 1995) would cause nearly a 400 percent increase in oil and gas use. Reserve margins would also decline from a national average of 45 percent under the base case in 1995 (where demand grows at an annual rate of 3.2 percent) to 25 percent. These averages mask regional variations, of course. The Northeast and Mid-Atlantic states would maintain more than adequate reliability levels, while the West would be required to construct oil-and gas-fired peaking units to maintain reliability. Again, the increased oil and gas use would occur primarily in base load in areas that are currently the most oil- and gas-reliant. Rates would increase the most in the California-Nevada-Arizona region (24.2 percent), followed by the Texas-Gulf States region (18.3 percent), New York (6.0 percent), and the Southeast (5.5 percent).

REGULATION AND UTILITY CAPITAL COSTS

An additional unnecessary cost burden involves the capital costs of utilities. Traditionally viewed as low-risk endeavors, utilities have lately been seen as riskier. Since 1973, Moody's has announced 79 lowered debt ratings for electric utilities and only 12 increases. Where utilities at the beginning of the 1970s were generally considered AAA credit risks, many

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5. (Continued)
not need all of the capacity now planned. Yet these savings are small in relation to the losses experienced elsewhere. The Los Alamos projections assume, however, that oil and gas prices rise at an annual rate of over 4.5 percent over the decade, so that oil prices reach $44 per barrel (in 1980 dollars) and gas prices the equivalent of over $43 per barrel by 1990. While assuming that a $30 per barrel figure to derive the initial excess production cost estimate may underestimate future oil prices, a $44 per barrel figure (or approximately $79 per barrel in 1990 dollars) appears excessive.

6. U.S. Department of Energy, Impacts of Financial Constraints on the Electric Utility Industry, DOE/EIA-0311 (December 1981).

are now two or three grades lower at A or BAA. Companies with lower credit ratings must pay higher interest rates to borrow. In early 1982, an A-rated electric utility had to pay about 100 basis points (one percentage point) more to borrow in the intermediate- and long-term bond markets than an AAA-rated utility. A borrower rated BAA had to pay 175 basis points, or 1.75 percentage points, more. This deterioration in utility bond ratings adds to the already existing burden of high interest rates.

Credit ratings are affected by regulatory behavior. It has been shown that utilities subject to regulation by PUCs classified as "favorable" benefit from equity capital (stock) costs that are nearly two percentage points less than for utilities operating in states where regulatory policy is regarded as "unfavorable."[7] The same holds for bond yields.[8]

The slowness of PUCs to grant rate relief is not the only way in which regulation affects the cost of financing utility investment. Another is the increased sensitivity of regulators to the environmental costs and risks associated with coal-fired and nuclear plants, which has lengthened the time required to plan, site, and construct a generating facility from an average of four or five years in the 1960s to about twelve years today. Longer construction periods, and the general unwillingness of PUCs to include CWIP in the rate base, require the utilities to borrow more per dollar of construction.

The regulatory procedures that determine whether the environment within which a utility operates is "favorable" are precisely those discussed earlier in this chapter. As has been seen, the substitution of AFUDC for CWIP has lowered the quality of utility earnings, and makes a utility vulnerable to future decisions by its PUC that may jeopardize its ability to recoup its AFUDC account. Regulatory lag has lowered utility earnings from the levels they were initially allowed. The use of historical test periods for measuring operating costs has biased utility earnings downward in an inflationary environment. The use of fuel adjustment clauses may have blunted utilities' incentives to replace outmoded capital equipment with newer generating stock. Oil and gas costs can be passed along automatically under fuel adjustment clauses, while capital expenditures to

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7. Robert R. Trout, "The Regulatory Factor and Electric Utility Common Stock Investment Values," Public Utilities Fortnightly (November 22, 1979).

8. S.H. Archer and G.H. Atkinson, "The Cost of Capital and State Regulation of Electric Utility Rates," Center for Business-Government Studies, Center Paper 79-7 (July 1979).

replace oil- and gas-fired generating equipment are impeded by the use of AFUDC with its effect on the "quality of earnings." In addition, many utilities may not be allowed to earn a rate of return that will cover the cost of capital for new construction. These features provide strong incentives to keep existing capacity running even if newer capacity would lower costs.

Thus, regulatory practice may cause a significant increase in utility capital costs. A rough estimate of these excess costs is possible if a number of assumptions are made. The cost of capacity additions may be assumed to average $1,000 per kilowatt in 1980 dollars over the decade of the 1980s. External financing (both debt and equity) may be assumed to account for 60 percent of capital requirements, and the additional cost of external financing attributable to PUC behavior may be estimated at 1 percent on average (100 basis points). Under these assumptions, ratepayers could experience higher annual capital charges of from $800 million to $1.1 billion per year. The $800 million yearly excess cost figure is associated with a supply scenario in which only 134 gigawatts of new capacity are added over the decade. The higher $1.1 billion per annum estimate is linked to supply additions of 200 gigawatts over the decade (the base case described earlier). The interest rate (the assumed aggregate average cost of debt and equity) in the absence of adverse regulatory practice is assumed to be 12 percent for the purposes of this estimate.

CHAPTER IV. POLICY OPTIONS

Previous chapters have shown that the financial condition and regulatory treatment of the electric utility industry may ultimately lead to a serious loss of efficiency. This could come about if utilities are led to defer or avoid new capital expenditures. First, the deferral of new capacity may result in utilities consuming the wrong mix of fuels--that is, more oil and gas and less coal--than would be suggested by economic considerations alone. Second, utilities may be forced to pay more for their capital if the financial market perceives them to be less desirable investments than in the past. Finally, if new capacity additions should fail to keep pace with demand in coming years, the costs of inefficiency could become even greater as utilities are forced to meet more demand with equipment and fuels best suited to intermittent or peaking uses.

This chapter discusses the policy options available to the federal government in this area. These are generally of two types: options that would circumvent existing state regulatory practices, and options that would deliberately alter them. This division is an important one. Options that circumvent the existing regulatory treatment of the electric utility sector may be inefficient or ineffective because they preserve the existing content of utility regulation. Options that deal directly with the regulatory treatment of utilities raise the issue of states' rights in this area, since electric utility regulation is considered the legitimate province of the states. This conflict between the efficacy of the available policy options and their interference with the existing rights of states will appear throughout the discussion.

POLICY OPTIONS

Options that would not involve changes in the regulatory process include:

- Reliance on general economic recovery. Improved financial conditions, as a part of general economic recovery, may lower the cost of capital and make capacity adjustments easier. In that case, no specific policy may be necessary.

- Subsidization. Utilities could be subsidized in making capacity adjustments, particularly if they involve substituting new baseload capacity for oil and gas. This could be done either through cash subsidies or by further liberalizing the benefits from the investment tax credit and accelerated depreciation.

Another set of options would involve amending the regulatory practices of state PUCs. These can be grouped as follows:

- Imposing federal rulemaking on state public utility commissions. The federal government could determine rules regarding specific regulatory practices that states would be compelled, or induced, to adhere to.

- Regional capacity planning. Capacity planning could be done on a regional rather than local basis to achieve greater efficiency and lower requirements for reserve margins.

- Deregulating the generation of electricity. The reserved monopoly position of electric generation could be amended through a variety of means to allow free competition among bulk suppliers of electricity. Transmission and distribution would remain subject to regulation.

The discussion below evaluates each option from standpoints of efficiency and fairness. The primary criteria of efficiency are cost-effectiveness in achieving capacity adjustment, and the speed at which that adjustment occurs. The fairness criterion involves the extent to which those who benefit from a change in generating capacity (and, conversely, oil and gas displacement) are those who pay for it.

EVALUATING THE NONREGULATORY OPTIONS

Reliance on General Economic Recovery

This approach would rely on general economic recovery to improve the economic environment of electric utilities, and hence their performance. Specifically, lower interest rates and less inflation would reduce the cost of adding or replacing capacity. An economic upswing could thus be expected to increase the rate at which new baseload capacity is substituted for oil- and gas-fired units. On the other hand, it could increase the demand for electricity, thus requiring continued use of oil and gas units even with a faster rate of new construction.

The extent to which economic recovery would increase the rate at which new capacity is added would depend on the behavior of regulators.

Lower interest rates might lead PUCs to reduce the allowed rate of return afforded utilities, passing the benefits directly to consumers. Also, present regulatory practices such as fuel adjustment clauses, the predominant use of AFUDC, and historical-cost accounting might continue to inhibit utility investment regardless of the rate of interest. As noted in Chapter II, failure to address these practices appears to have limited utilities' access to capital and to have increased the cost of that capital.

A utility policy that relied entirely on improvement in the general economy would avoid the equity problems of the next option--that of subsidizing investment in electric generating capacity. It should be noted, however, that current regulatory practices themselves involve a form of subsidy. To the degree that they result in uneconomic rates of replacement for oil and gas capacity, they increase the costs of future electricity production, thus subsidizing current ratepayers at the expense of future ratepayers.

Subsidization

A subsidy in the form of federal grants or tax relief to utilities could assist them in making economic capital expenditures. The subsidy could be linked to a schedule for new capacity additions. One way to do this might be to convert the tax or cash subsidy to a government loan repayable with interest if the construction schedule was not met. Alternatively, if reconversions of coal-capable oil-fired units were not completed on schedule, recovery of oil and gas costs through the fuel adjustment clause could be prohibited after that time. The subsidy would as a rule cover only a portion of the capital costs associated with new capacity so that utilities would have to rely on the capital market, or on retained earnings, to finance the remaining portion.

Cash Subsidies. Even though a cash subsidy might be effective in hastening capacity adjustment, the unsubsidized portion of accelerated construction would still be quite substantial. Since the regulatory environment would remain unaltered, this portion might become increasingly difficult to finance. This is particularly relevant for those utilities under the greatest financial duress. The failure of this alternative to address all the financial obstacles, combined with the fact that a subsidy offers no way of reducing the risks associated with future demand uncertainty (and no way of streamlining the licensing process to shorten delays), might lead to continued shortfalls in new capacity.

Cash subsidies also fail to differentiate between electric utilities in poor financial health and those in relatively good standing. Each utility would receive a fixed percentage of the capital costs associated with new construction expenditures regardless of its financial position, providing a windfall to those in good health and not enough incentive to those in straightened circumstances. Moreover, subsidies may reward managerial inefficiency if they assist equally those utilities whose difficulties stem from poor management and those in poor financial health because of factors beyond managerial control. In addition, a cash or tax subsidy fails to differentiate between good regulatory practice and bad. To the extent that it rewards the latter, the subsidy may perpetuate the condition it is intended to remedy. A subsidy may also lead to a failure to adopt the least-cost investment alternative. For example, an oil- or gas-reliant utility might opt for the construction of a new coal-fired unit if it is subsidized, even though that may be more expensive than other options such as conservation or load management.

Subsidizing the entire electric utility industry, it can be argued, would make it unnecessary to address the particular inefficiencies of state utility regulation. But it would also shield ratepayers from the true cost of energy at a time when economic efficiency requires the use of appropriate price signals. Since ratepayers will be the prime beneficiaries of fuel switching in the generation of electricity, both efficiency and equity may dictate that they pay for this conversion. In any event, the government cannot know the economically correct rate of oil and gas replacement. To the extent that it pays too much or too little into the subsidy program, the outcome will be inefficient.

For the oil- and gas-reliant subset of the industry, there is another argument for subsidization. It can be argued that the entire nation, as well as ratepayers in oil- and gas-reliant regions, would benefit from fuel switching since it would diminish U.S. reliance on oil imports. This argument, however, overlooks the fact that it is in the interest of ratepayers to make these expenditures. The general argument for government subsidization is that intervention should occur when particular expenditures are not in the self-interest of individuals and when all citizens would benefit. Chapter III has established that reconversions to coal and accelerated construction of new coal-fired units are often in the interest of particular ratepayers and would lower the costs they pay for electricity. The fact that benefits would accrue to all citizens from a reduction in oil and gas use is not an argument for government subsidies, since these benefits would occur anyway if the regulators sought to provide electricity at the lowest life-cycle costs to their ratepayers. Finally, such a subsidization could prove expensive. If half of the 120 gigawatts of oil- and gas-fired generating capacity that cannot be converted to coal use were retired ahead of schedule, and if 10 percent of their capital costs were defrayed by federal subsidy, the cost to the federal government would be over $6 billion, assuming a cost of $1,080 in 1982 dollars per kilowatt of capacity.

Tax Subsidization. Another subsidy option would increase the electric utility industry's cash flow by further liberalizing the benefits of the investment tax credit and accelerated depreciation. The investment tax credit (ITC) allows a utility to deduct a fixed percentage of its investment expenditures from its tax liability. It therefore subsidizes capital formation. Since its inception in the Revenue Act of 1962, the ITC has been extended to electric utilities in various forms. The Revenue Act of 1978 instituted a 10 percent ITC for utilities, or 15 percent for capital expenditures associated with oil and gas displacement activities. Accelerated depreciation, on the other hand, acts as an interest-free loan that defers the taxes utilities must pay. The current asset depreciation range (the statutes that give the depreciation lives for capital equipment) was formed in 1971. Utilities could be further subsidized by shortening these ranges.

A fundamental problem with tax subsidization of electric utilities has been the limited federal tax burden borne by them. In 1979 and 1980, for example, utilities paid only $743.5 million and $1.24 billion, respectively, in federal taxes, or about one-fourth of their book tax rates. In fact, 51 (or 25 percent) of 203 private electric utilities paid no federal taxes in 1980. The Economic Recovery Tax Act of 1981 (ERTA) allowed the leasing of equipment between parties in order to transfer the attendant tax benefits, effectively creating an open market for tax benefits in excess of liabilities. This implicit "refundability" allowed tax benefits to be transferred to utilities even if they exceeded their tax liabilities. The Tax Equity and Fiscal Responsibility Act of 1982, however, limited this ability and eliminated the leasing benefits found in ERTA (although leasing may still occur under more limited rules). ERTA also allows investors preferential tax treatment of utility dividends, if those dividends are taken in the form of common stock. If dividends are taken as stock, the investor may defer taxes paid on them until the stock is sold, the proceeds then being subject to capital gains treatment (implying a lower marginal rate).

Tax subsidies carry the same general advantages and disadvantages as a cash subsidy. The advantages lie in the possibility that some oil and gas displacement activities will be accelerated through the conveyance of the subsidy. The disadvantages concern the efficiency and equity with which subsidies achieve this benefit. Subsidies reward all utilities involved in oil and gas displacement activities, even where these activities have been deferred because of regulatory practices or poor management. Moreover, subsidies do not necessarily lead to least-cost generating options. Rather, they are solely concerned with retirement or reconversion of oil- and gas-fired baseload units, and therefore may induce utilities to overlook other technical displacement activities, such as grid interconnection, conservation, or load management. Moreover, while subsidies may lead to reduced oil and gas consumption by utilities, benefiting the entire nation through lower oil imports, such reduced consumption often results in lower electricity prices to consumers. This means that ratepayers in affected regions might be subsidized for actions that would be in their own benefit even if unsubsidized.

In addition to these general considerations, there is uncertainty regarding the incidence of the benefits of tax subsidies. State regulators might opt to direct the benefits to consumers through lower electricity rates. As discussed in Chapter II, these benefits could be treated in either a "flow-through" or a "normalized" manner. Under the former, benefits are accounted for as they are incurred, and therefore the probability that they will be passed through to consumers is increased. Under normalization, the benefits are normalized over a period of time; this procedure conveys a larger portion of tax benefits to the utilities themselves. The Economic Recovery Tax Act of 1981 directed that state PUCs must use normalized accounting when treating the tax benefits associated with the provisions of that act. This treatment may make the tax benefits more effective in reducing oil and gas consumption, although most states already normalize tax subsidies. The tax leasing provisions of ERTA were curtailed in the Tax Equity and Fiscal Responsibility Act (TEFRA) of 1982. The net effect of the two on the status of leasing is not yet evident, but estimates of the cash flow benefits from the accelerated cost recovery provisions of both are possible. ERTA further liberalized accelerated depreciation for electric utilities, while TEFRA curtailed some of these benefits. Table 10 presents the projected yearly electric utility tax reduction estimates for both TEFRA and ERTA through 1986 compared to previous law. TEFRA is estimated to reduce the tax burden of electric utilities by $4.5 billion over this period, $1.2 billion less than ERTA would have. Based on the recent experience of private electric utilities, their federal tax burden may be eliminated in 1984 or 1985.

TABLE 10. ELECTRIC UTILITIES' ESTIMATED TAX REDUCTION UNDER THE ACCELERATED COST RECOVERY SYSTEM OF THE ECONOMIC RECOVERY ACT OF 1981 (ERTA) AND THE TAX EQUITY AND FISCAL RESPONSIBILITY ACT OF 1982 (TEFRA) (By calendar years, in millions of dollars)

	1982	1983	1984	1985	1986
ERTA	353	725	921	1,363	2,373
TEFRA	353	725	921	1,157	1,336

SOURCE: Donald W. Kiefer, Congressional Research Service; and the Treasury Department.

EVALUATING THE REGULATORY OPTIONS

Several policy options are available that would amend the regulatory practices of state PUCs in an effort to improve the economic performance of utilities:

- o Imposing federal requirements on state rulemaking;
- o Requiring capacity planning on a regional basis; and
- o Introducing greater competition through deregulation of generation.

All of these options would, in varying degree, preempt the traditional right of states to regulate their electric utilities. This raises a question as to whether they could be implemented without protracted legal challenges.

Imposing Federal Requirements on State Rulemaking

The first regulatory option would limit the discretion available to PUCs in regulating their utilities, substituting some federal guidance for state decisionmaking. Federal guidelines might include the following:

- o Limits to the allowed rate of return on common equity. Such a guideline would require that the allowed rate of return determined by PUCs be tied to the structure of interest rates. Alternatively, some standard of financial health could be established, allowing higher rates of return to utilities that fell outside the standard.
- o Inclusion of CWIP in the rate base. Guidelines could be formulated to require the inclusion of construction work in progress in the rate base, as opposed to the use of AFUDC accounts, as discussed in Chapter II.
- o Allowance of higher rates of return based on the performance of electric utilities. Should new capacity result in net "avoided costs," some portion of these avoided costs could be directed to utility earnings. This would give utility companies a direct financial stake in least-cost generation.
- o Amendment of fuel adjustment clauses. The use of fuel adjustment clauses could be amended to encourage fuel-switching investments.

Advantages. Imposing federal requirements in these ways would offer both advantages and disadvantages in reducing utility oil and gas consumption. Such rulemaking would directly confront the regulatory practices that have been observed to inhibit utility capital formation. Allowing higher rates of return or reducing the use of AFUDC would contribute to more investment, and also to lower capital costs as the financial community perceived less risk in utility borrowing.

These options would also assign capital stock adjustment costs to their primary beneficiaries--the ratepayers in areas now served by uneconomic generating equipment. They might also eliminate the possible tendency to subsidize future ratepayers at the expense of current ratepayers that is associated with the use of AFUDC instead of CWIP.[1]

Analysts sometimes speak of an "asymmetry of risk and reward" in utility investments.[2] That is, when new plants work as anticipated, the benefits are often shared with consumers, leaving the utility's stockholders only slightly better off. But when new units fail, the utility may be expected to cover the cost out of its profits. The Supreme Court recently

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1. An equity concern traditionally associated with the adoption of CWIP is that current ratepayers, by paying for construction work as it occurs, will be purchasing capacity that will serve future ratepayers, thereby subsidizing them. The use of AFUDC, on the other hand, is often held to shield ratepayers from power plant costs until the plant becomes "used and useful." But this shielding may not work well in practice. As the accounting earnings from AFUDC substitute for cash flow in a utility's balance sheets, investors may consider that utility's bonds less desirable. This causes them to demand a higher return on their investment, increasing the cost of capital to the utility. The higher capital charges must be borne by present as well as future ratepayers. Perhaps more important from the perspective of public policy, the use of AFUDC may cause a utility company to postpone construction that would eventually mean lower operating costs. The failure to lower costs is a burden imposed on future ratepayers by current ones. Finally, to the extent that regulation aims at reproducing the effects of the market, it is worth noting that in most of the economy future production capacity is paid for by current consumers. Thus, the argument that CWIP provides a subsidy to future ratepayers at the expense of present ratepayers is not conclusive.

2. "Balancing Risks and Rewards to Reduce Financial Disincentives to Power Plant Construction," Public Utilities Fortnightly, vol. 107, no. 4 (February 12, 1981), pp. 21-25.

refused to overturn an Ohio State Court decision that ratepayers were not liable for the costs of generating units not placed into service. Thus, utility management is not rewarded when new capacity functions without incident, but stands at risk when new capacity does not work or is deemed unnecessary upon completion. This creates an asymmetry between the risk and reward associated with building new power plants. A generic rule that would allow utilities to earn a fixed percentage of the avoided cost associated with any power plant investment would correct this asymmetry and be an inducement to further investment.

Disadvantages. The disadvantages associated with generic rulemaking are twofold. First the use of rulemaking, most likely by the Federal Energy Regulatory Commission (FERC) would effectively substitute federal for state decisionmaking. Such an intrusion would probably lead to court challenges, and would raise questions of fairness at a time when many other federal functions are being turned over to the states.

Second, generic rules may be "untargeted" in the same way that subsidies are untargeted, with the result that both utilities in financial distress and those that are financially sound would benefit from generic regulatory guidelines. This would reduce the efficiency of such rulemaking.[3]

While generic ratemaking guidelines could assist utilities in realizing higher rates of return, this addresses only one dimension of the capital disincentive problem. The other major disincentive is the ubiquitous use of fuel adjustment clauses (FACs). In the short term, FACs may lead utilities to pay too high a price for available fuel since these costs can be recouped easily. There are various ways to eliminate this bias. State PUCs could monitor fuel purchasing practices to see that the least expensive fuel of a given quality is bought. But this short-term bias is not the principal problem associated with FACs. The fuel-switching and operation and maintenance biases discussed in Chapter II result in much larger economic losses over the long term. To combat the fuel-switching bias, PUCs could employ an oil conservation adjustment clause such as that adopted in Massachusetts. This provision allows utilities to recoup capital expenditures in reconverting

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3. This does not apply to a generic rule assigning a share of avoided costs to utility earnings. The problem would be avoided under this specific rule because such "performance bonuses" would be directly tied to the provision of lower-cost electricity. This would avoid the inequities associated with providing aid to utilities that do not require it to remain solvent or attractive to investors while assisting utilities that are in a predicament because of poor management.

coal-capable oil-fired units through the fuel savings such an investment entails. Specifically, it allows utilities to retain two-thirds of the fuel savings attributable to the fuel-switching investment in a given year, while passing on the remaining one-third to consumers until the investment expenditures have been recovered. This type of clause could be extended to new coal-fired units, although the recoupment time would be much longer than that associated with reconversions. A remedy for the bias against operation and maintenance expenditures could be the inclusion of these costs in the FAC mechanism. This might lead to the opposite bias of overmaintenance, but given the very favorable payoff from additional maintenance (cited in Chapter II), the inefficiency would probably not be as great as the higher fuel costs presently experienced from undermaintenance.

Completely eliminating the FAC could be financially debilitating for the industry. Other means, such as reducing the percentage of sales covered by the clause, or increasing the recovery lags for fuel cost increases, might prove helpful in curbing these sources of inefficiency.

Requiring Capacity Planning on a Regional Basis

State regulation of electric utilities originated at a time when the scale of electrical generation was sufficiently small that all of its costs and benefits were contained within one state. Contemporary generating facilities, however, have grown to the point where the construction of new generating facilities can affect the supply alternatives of nearby states. Thus, increased interstate coordination of capacity may offer substantial economic benefits, including decreased oil and gas consumption by the affected utilities and the pooling of reserve capacity.

Regionalized capacity planning could be brought about in several ways. Those discussed here include the following:

- Ordering increased interconnections of state grids. Under current statutes, FERC has the authority to order interconnections and to order greater bulk power exchanges.

- Inducing or mandating the creation of regional regulatory bodies. State PUCs could be induced (through incentives) or required to coordinate capacity additions to neighboring states.

- Allowing out-of-state "least-cost alternatives". A state with excess generating capacity could be allowed to petition the PUCs of neighboring states for recognition as a "least-cost alternative." Utilities with excess capacity could thus assist in meeting demands in neighboring states.

Advantages. Each of these options would make lower-cost electricity available to consumers. They might also reduce utility oil and gas consumption by making better use of coal-fired capacity. Regional capacity planning would allow states to lower their reserve margins by pooling the risks of surges in peak demands, particularly when planning regions fall in different time zones or have different seasonal peak demands. Moreover, many areas with excess generating capacity fueled by coal, nuclear energy, or hydropower are adjacent to areas with slim capacity margins and significant oil- and gas-fired capacity.

An example of such complementarity can be found in the Northwest and California. The Northwest may have significant excess capacity once its remaining reactor projects are completed. It already has intermittent excess capacity from its hydroelectric system. California, on the other hand, has delayed many recent capacity additions, and has a decreasing reserve margin. Each of the three regionalization options could be applied to this situation.

Increased transmission ties between two areas could be ordered by FERC, using statutes found in current law. FERC has, under section 202(b) of the Federal Power Act, the authority to force a utility to interconnect with another utility if it finds that to be in the public interest. Section 202(h) of the same act grants FERC the authority to establish a board composed of members of the relevant PUCs to resolve the administrative problems associated with such coordination. In addition, the Public Utility Regulatory Policy Act amended the Federal Power Act so that FERC may now order the transmission of power by any utility to any requesting electric utility or federal marketing agency if it is in the public interest or if it will result in significant energy conservation, promotion of efficiency, or improved reliability of the requesting utility. However, FERC has been reluctant to require the establishment of regional regulatory bodies. Rather, it has preferred to limit its role to regulating the sale of interstate wholesale electric power and to encouraging voluntary coordination. It could, nonetheless, order such ties, or establish a regional council to coordinate the wheeling of excess Northwest electricity to California. Alternatively, the Congress could legislate the creation of such councils, or provide incentives to states to participate in them.

Disadvantages. The principal disadvantage associated with interregional links is the intrusion on the right of states to regulate electricity sales within their boundaries. Moreover, some states may not view regional coordination as being in their interest. A state with excess generating capacity might be unwilling to send power to another state, perhaps because of the environmental costs of using that capacity--even though it would reduce unit costs for consumers in both states. States with low reserve margins, the natural recipients of interstate power sales, might prefer to build their own capacity despite potentially higher costs. In the Northwest/California example, California utilities might oppose out-of-state power since it would obviate the need for more generating capacity in California and in doing so reduce the California utility's potential rate base.

The Least-Cost Option. One way of minimizing the intrusion on states' rights would be to allow out-of-state sources to petition a state PUC for recognition as a "least-cost alternative." State PUCs permit additions to capacity when utilities demonstrate that such an addition would be the least-cost method of meeting new demand, or that it would result in the retirement of units with higher generating costs. Out-of-state sources could be invited into this least-cost determination. In the Northwest/California example, utilities in the Northwest could petition the California PUC for recognition as a potential least-cost capacity addition. This would allow for regionalization of capacity planning on its economic merits, while preserving the integrity of state regulation.

Introducing Greater Competition

A third approach to the problem of utility capital stock adjustment would be to foster greater competition among generating facilities by deregulating the generation stage of electricity production. Electricity production occurs in three separable stages: electricity is generated in power plants, then transmitted to localities, where it is distributed to individual users. The regulatory process has historically considered the entire electricity industry as a natural monopoly--that is, as an industry in which unit costs continually decline as output expands, so that a monopoly will have the lowest costs. It is argued that efficiency dictates the granting of regulated regional monopolies in the generation, transmission, and distribution of electricity. But accumulated evidence suggest that declining costs are not true of the entire industry. In the transmission stage, costs decline significantly as voltage capability increases. With respect to generation, however, cost reductions associated with increases in output are not significant over a large range of firm size, and disappear long before output levels approach the size of the larger electric utilities operating today. At the distribution stage, costs are related more to customer density than to the total output of a utility. Hence, cost considerations alone do not appear to warrant the current market structure for the electric utility industry.

One response would be partial deregulation, perhaps through establishment of Regional Distribution Corporations (RDCs) which would own all of the transmission lines in a particular area.[4] The RDCs might be regulated by the Federal Energy Regulatory Commission because of the interstate business they conduct. The transmission lines would then act as common carriers for electricity, with the RDCs leasing generating capacity from independent producers. In turn, the RDCs would transmit the electricity to local distribution companies. These distribution companies could also own the generating units, but would not be able to control the transmission network. This would prevent the exercise of monopoly power that isolates small distributors from the coordinated grid shared by vertically integrated utilities. The distribution stage would still be regulated by state PUCs.

Advantages. Such a deregulation could convey several economic advantages. By fostering competition, it would give preference to least-cost generating options. It might also be a more expeditious way of displacing oil and gas than other alternatives. An RDC would create incentives to "wheel" power interregionally, taking more advantage of the power transfer opportunities associated with regional coordination. In addition, small publicly owned utilities not able to raise sufficient capital to install optimal size generating units would benefit from the lower costs of power wheeled from larger generating units. This would also displace oil and gas, since many of these publicly owned utilities are forced to utilize smaller oil- and gas-fired units because of their lower capital costs.

Disadvantages. Deregulation would pose a series of uncertainties, however, and raise new issues. One issue would be the adequacy of electricity supplies in a deregulated generating industry where generating companies would not be obligated to meet any level of demand. Regulated utilities are obligated to provide electricity to meet peak demands, and to plan adequate capacity for the long run. The costs of providing peak electricity are higher than the costs of baseload, often more than double. Since PUCs generally average in the costs of peak and baseload generation, current regulatory procedure effectively subsidizes peak uses of electricity with revenues from sales of baseload electricity. This cross-subsidization of electricity uses through the regulatory process allows the provision of peak power. Such cross-subsidization would not occur in a deregulated industry.

If peak power was not cross-subsidized in a deregulated generating industry, two possible problems might emerge. Generating firms might be unwilling to provide peak power, which would lead to brown-outs or other curtailments during peak demand periods. Or generating firms might

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4. See, for example, Matthew Cohen, "Efficiency and Competition in the Electric Power Industry," The Yale Journal, vol. 88 (June 1979), pp. 1511-49.

provide peak power but charge peak-power rates for all their sales to transmission companies. If a free market for electricity were to result in a single price for all electricity reflecting the costs of peak power generation, substantial profits would be realized by baseload power producers, and electricity prices would rise dramatically.

This pricing problem could be overcome by appropriate actions on the part of the transmission and distribution companies. Transmission companies, when buying electricity from generating stations, could be required to exercise "price discrimination"--that is, to offer higher prices only for electricity purchased during peaks. Thus, transmission and distribution companies would pay different rates for electricity provided during different times or seasons, but would charge one average price to consumers, continuing the cross-subsidization of electricity uses now common to electricity regulation. Exercising this price discrimination, however, would require new institutions to create a competitive market between generation and transmission. For example, a central dispatch office, representing the transmission grid, could receive hourly electricity "offers" from generating units that wished to supply electricity, a system now used to create a "spot market" for electricity in Florida.[5] It could then accept the lowest-cost offers that met the level of demand placed on the grid. In addition, distribution companies could be required to install "time of day" meters on all electricity users. These meters would be sensitive to the time when electricity was consumed, and would therefore allow consumers to be charged a price for electricity that reflected the costs of its generation. Such metering is technically possible, although a substantial amount of administrative effort would be required to implement it. Thus, the problem of providing peak power in a deregulated generating industry can be solved, but its solution calls for new actions on the part of the transmission and distribution system.

The long-term supply problem would be more difficult. In the face of demand uncertainty, unregulated generating companies might tend to be conservative in planning new capacity. This would transfer more of the risk associated with capacity planning to consumers. Given the long lead times required for new capacity construction, the costs associated with underinvestment in new generating capacity could be substantial. In this respect, electricity generation differs from other industries that have benefited from deregulation, such as trucking and airlines. The underinvestment problem might be solved by allowing transmission companies to buy contracts for future delivery of electricity from firms planning to build new generating

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5. The Rand Corporation, A Spot Market for Electricity: Preliminary Analysis of the Florida Energy Broker (February 1982).

capacity. This would provide early capital and assured funding to the builders of new power plants, but would still transfer more risk to consumers than they now bear. Offsetting this, electricity prices would move toward least-cost levels as competition developed.

It is also important to consider the impact of deregulation on individual firms within the utility industry. Many utilities dependent on oil and gas as generating fuels would find themselves unable to compete in a deregulated environment. Their generating units would be displaced by coal, nuclear, and hydro baseload units as transmission grids shopped for the lowest electricity prices offered by generating firms. This is the potential strength of deregulation--the displacing of oil and gas in electrical generation. Yet it would leave such utilities with unprofitable generating units, many of them with years remaining on their amortized lives. These units would have to be retired before they were paid for, inflicting economic losses on the utilities and their stockholders. Such costs might be considered unfair, since many utilities might have been prevented from retiring these units because of current regulatory practice. Such utilities would enter a deregulated environment with a competitive disadvantage, exposing them to heavy losses because of their "starting postion" in a deregulated utility industry. On the other hand, many publicly owned utilities--which enjoy significant tax and financial subsidies--would be the unintended beneficiaries of a deregulation policy. These subsidies might be reappraised in a deregulated generation industry.